AR92

2007 Annual Report


ng Lake

billions of barrels of oil sands inventory

millions of deep-water barrels ready for development

thousands of acres of exploration potential

hundreds of opportunities to apply new technologies

Charlie Fischer
Nexen's President and CEO

"It comes down to this one choice—build a sustainable energy company. From there, the decisions are easy. See beyond short-term market storms. Bring together passionate people, inspired by innovation. Accumulate an unbeatable inventory. Transform knowledge into power and possibilities into projects. Compromise nothing and improve everything. Build assets that create legacies like Yemen and Buzzard. Long Lake is next."

president's review

	2007	2006	2005
Cash Flow from Operations ($ millions)	3,458	2,669	2,403
Cash Flow per Share ($/share)	6.56	5.09	4.62
Net Income ($ millions)	1,086	601	1,140
Net Income per Share ($/share)	2.06	1.15	2.19
Capital Expenditures ($ millions)	3,401	3,330	2,638

It was a year of solid accomplishments at Nexen. Operationally, we brought Buzzard on stream and increased production after royalties by 33%. Financially, we achieved net income of $1.1 billion or $2.06 per share and record cash flow of $3.5 billion or $6.56 per share as we benefited from the full impact of high oil prices. We also received a number of accolades for the way we do business including for our transparent disclosures and comprehensive sustainability reporting.

Our greatest achievement was the successful ramp up of Buzzard in the North Sea, which began producing early in 2007. Buzzard is one of the few mega projects worldwide in the last several years to be completed virtually on time and on budget. In its first year of operations, Buzzard achieved first quartile uptime performance for a new offshore facility in UK North Sea and was the single largest contributor to our 30% cash flow growth. Over its life, this world-class asset is expected to produce well over 600 million barrels of oil (260 million barrels net to us) and generate significant value for Nexen.

Despite success at Buzzard, we missed our 2007 production targets. In addition to modest timing delays at Buzzard, the start up at Long Lake was deferred almost six months, and at Aspen in the Gulf of Mexico, we had disappointing results from development drilling. Going forward, we've already made a number of changes to improve project performance. At Buzzard, we're focusing on continuously improving uptime so the platform consistently operates at full rates. At Long Lake, we are integrating the lessons from Phase 1 and other projects into our plans for subsequent phases. To support our strategic initiatives in the US, we have restructured our operations to focus on improving our capabilities in the deep-water Gulf of Mexico. With these changes underway, we are well positioned for a successful 2008.

This year we are excited to bring Phase 1 of Long Lake on stream. We are currently steaming the reservoir through all well pads and upgrader construction is more than 97% complete. Our oil sands strategy integrates steam-assisted-gravity-drainage (SAGD) and upgrading technology to produce the highest quality synthetic crude in the region. The patented process minimizes the need for purchased natural

Did you know Charlie Fischer provides a quarterly update on our operations and financial results? Keep up to date by visiting ***www.nexeninc.com/reports/A1.asp***

	2007	2006	2005
Production before Royalties (mboe/d)	254	212	242
Production after Royalties (mboe/d)	207	156	173
Proved Reserves [1] (mmboe)	1,058	1,049	786
Proved + Probable Reserves [1] (mmboe)	1,964	1,651	1,621

1 Represents our working interest before royalties using year-end pricing and includes our Syncrude reserves.

gas and provides us with an expected $10/bbl operating cost advantage over existing technologies. Phase 1 only develops about 10% of our oil sands leases. Once we gather enough operating history and receive clarity on proposed regulatory changes associated with climate change and royalty rates, we expect to sanction Phase 2. Future phases should follow an approximate 3-year cycle. Over the next decade, we plan to grow our oil sands production to approximately 120,000 bbls/d. With our significant land position and cost advantage, it is easy to see that oil sands will generate value growth for many years.

Yet there's more to develop and bring on stream in our global portfolio. In the North Sea, our Ettrick development is progressing well towards first oil mid 2008. We expect production to ramp up to approximately 30,000 boe/d (24,000 boe/d net to us) by year end. We have also identified a number of exploration opportunities in the immediate area that could be tied back to Ettrick and plan to evaluate at least two of these in 2008. Throughout the North Sea, we have hundreds of thousands of undeveloped acres, including nine licenses offshore Norway where we hope to drill our first well in 2009.

Our 2007 highlights include record cash flow, 33% growth in net production and the successful ramp up of Buzzard. What's next? In 2008, we'll bring on Long Lake and Ettrick, and drill up to 11 exploration wells.

Offshore Nigeria, development of the world-class Usan discovery continues to move forward, and we expect to award major deep-water facilities contracts soon. As we develop Usan, we also plan to continue exploring the highly prospective acreage in the area.

We also have a vast inventory of diverse opportunities in North America. In the Gulf of Mexico, we have significant deep-water acreage and have contracted two new deep-water rigs scheduled to arrive in mid 2009 and 2010. In addition to our active exploration program here, we also plan to appraise our exciting discoveries at Knotty Head and Vicksburg to define their potential. In Canada, we are the first company developing coalbed methane (CBM) in Alberta's Mannville coals where we have extensive land holdings. And in northeast British Columbia, we have a material land position in an emerging shale gas play and are currently testing this opportunity in what has the potential to be one of the most significant shale gas plays in Canada.

Looking at the company, I believe we have the talent and discipline to turn these opportunities into value-generating projects. I'm excited to see a new generation of employees at Nexen. They are young, energetic people who value integrity, diversity, innovative thinking and our rich portfolio of worldwide assets. Once again our employees named us one of the 50 Best Employers to work for in Canada. This is a great measure of our success in a world where human potential is truly the world's richest resource. I thank all employees, our participative Board of Directors and committed shareholders who all see value in **what's next.**

Charlie Fischer

President and CEO

today, tomorrow and beyond

Marvin Romanow
Executive Vice President and Chief Financial Officer

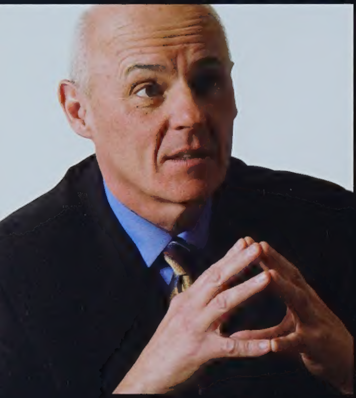
We asked Marvin: In 2007, Nexen's net production grew by 33%, but you don't expect growth of this magnitude for a few years until projects like Usan, Knotty Head and Phase 2 of Long Lake come on stream. Do you believe growth should be the company's strategic focus?

If we grow volumes but no value, our shareholders are worse off—we'll have paid too much for the barrels. If we focus solely on growth, we'll walk away from properties as soon as we see the slightest decline, leaving lots of value in the ground.

Our capacity to add value is driven by the quality of three ingredients: portfolio, projects and people. We have all of these in abundance. Our portfolio includes undeveloped conventional discoveries, oil sands development, non-conventional plays such as CBM and shale gas, and exploration prospects. That's a rich inventory with numerous opportunities to mitigate production declines in mature properties.

Our projects are high quality as well. For example, Buzzard's low operating costs and no royalties allow us to realize about 85% of the price of Brent before taxes. This means that at current oil prices, we expect to recover our total investment in Buzzard, including acquisition costs, in less than two years. We also did not hedge away the upside and our shareholders are benefiting 100% from strong oil prices. Equally impressive, Buzzard is helping us generate significantly higher company-wide operating cash netbacks per barrel—in some cases 50% better than our peers. This means for every barrel we produce, some competitors have to produce one and a half barrels to generate the same cash flow. All barrels are not created equal and the more value we create with each barrel, the more capacity we have to plan for what's next.

The final ingredient is our people. We must engage people's minds, inspire creativity and reward success. Part of this is deploying people in roles they are best suited for and developing their passions and strengths. The other part is creating a great work environment that allows talent to flourish. I believe when a company does these things well, value creation is the natural outcome.



Roger Thomas
Executive Vice President, North America

We asked Roger: Since the Long Lake pilot performed below initial expectations and there's proprietary upgrading technology involved, what gives you confidence this project will be a great success?

We're very confident in Long Lake and excited to bring it on stream this year. Any time you break new ground with a new technology or process, there's initial skepticism surrounding its success. I'd say our greatest indicator that we're on track is that many competitors are now trying to make gasification work for them.

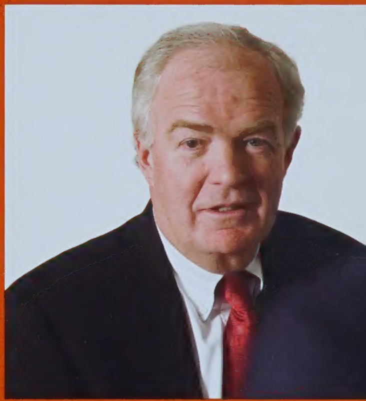
Did you know we have a diverse and experienced executive management team? Learn more about our leaders at ***www.nexeninc.com/reports/A2.asp***

And here's why. With our integrated gasification process, we convert the bottom of the barrel into synthetic gas, which substantially reduces our need to purchase natural gas—a key cost driver in oil sands production. At current prices, this translates into an estimated $10/bbl operating cost advantage.

The appeal of the patented process is its simplicity. It takes conventional "pots and pans" and uniquely configures them. We know the "pots and pans" work—gasifiers and hydrocrackers have been operating globally for decades. We also know the OrCrude process works—it was successfully tested in a demonstration plant for two years.

The SAGD pilot provided us with valuable learnings, including how to operate wells drilled into lean zones where less than half the zone is bitumen and steam oil ratios are higher. We now have over 300 cored wells within our commercial area and our geologic mapping indicates lean zones represent less than 3% of the total reservoir volume. So we're confident our commercial performance at Long Lake will exceed results from the pilot and steam oil ratios will be better than other projects in the area.

Phase 1 is just the beginning of what's next as Long Lake will only develop about 10% of our oil sands leases. We can therefore potentially duplicate Long Lake up to 9 times. With a $10/bbl operating cost advantage and low development costs per barrel, this is a legacy asset in the making.



Larry Murphy
Executive Vice President, International Oil and Gas

We asked Larry: Buzzard was one of few global mega projects in the last several years to be completed virtually on time and on budget, yet it missed its 2007 production goal. What happened?

Buzzard was definitely a highlight in 2007. We committed to a safe start up for this asset, taking care to protect our people and the environment. And we achieved that goal. Let me take you through the story.

We set an aggressive first-year target for Buzzard—to safely ramp up production to 190,000 boe/d gross, or 95% of name-plate design through the latter half of 2007. Instead we achieved 88% of this target which is still first quartile performance for a new offshore facility in the UK North Sea. A few factors set us back. A two-month delay in start up cost us about 9,000 boe/d in lost production. Considering Buzzard was a 42-month project, this delay was modest. We lost similar volumes due to operational downtime typical with commissioning and start up of a new facility. And the remaining shortfall was caused by third-party export facility outages. We're pleased to have these setbacks largely behind us and Buzzard is now operating well. In fact, production for January 2008 was over 220,000 boe/d (95,000 boe/d net).

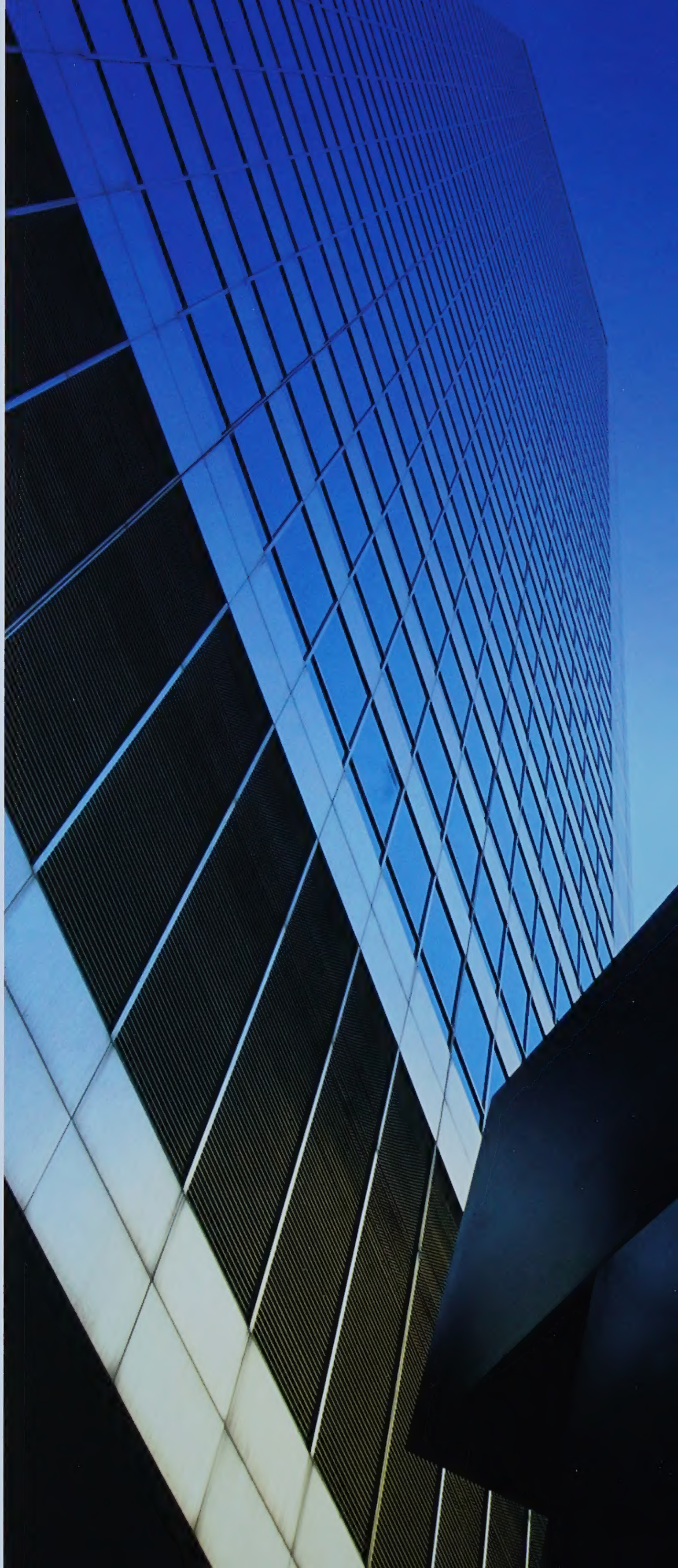
Buzzard is a world-class asset that keeps getting better. When we acquired it in 2004, we expected the field's ultimate recovery to be around 486 million boe gross. Since then, our reserves estimate has grown 35%. With current oil prices almost three times higher than when we made the acquisition and a facility that can handle greater volumes than originally forecasted, we see exceptional value from Buzzard.

Looking back, I am proud of how we delivered and operated Buzzard in 2007. We did not take shortcuts to achieve production goals and operated in a safe and responsible manner, keeping with Nexen's values and how we operate around the world.

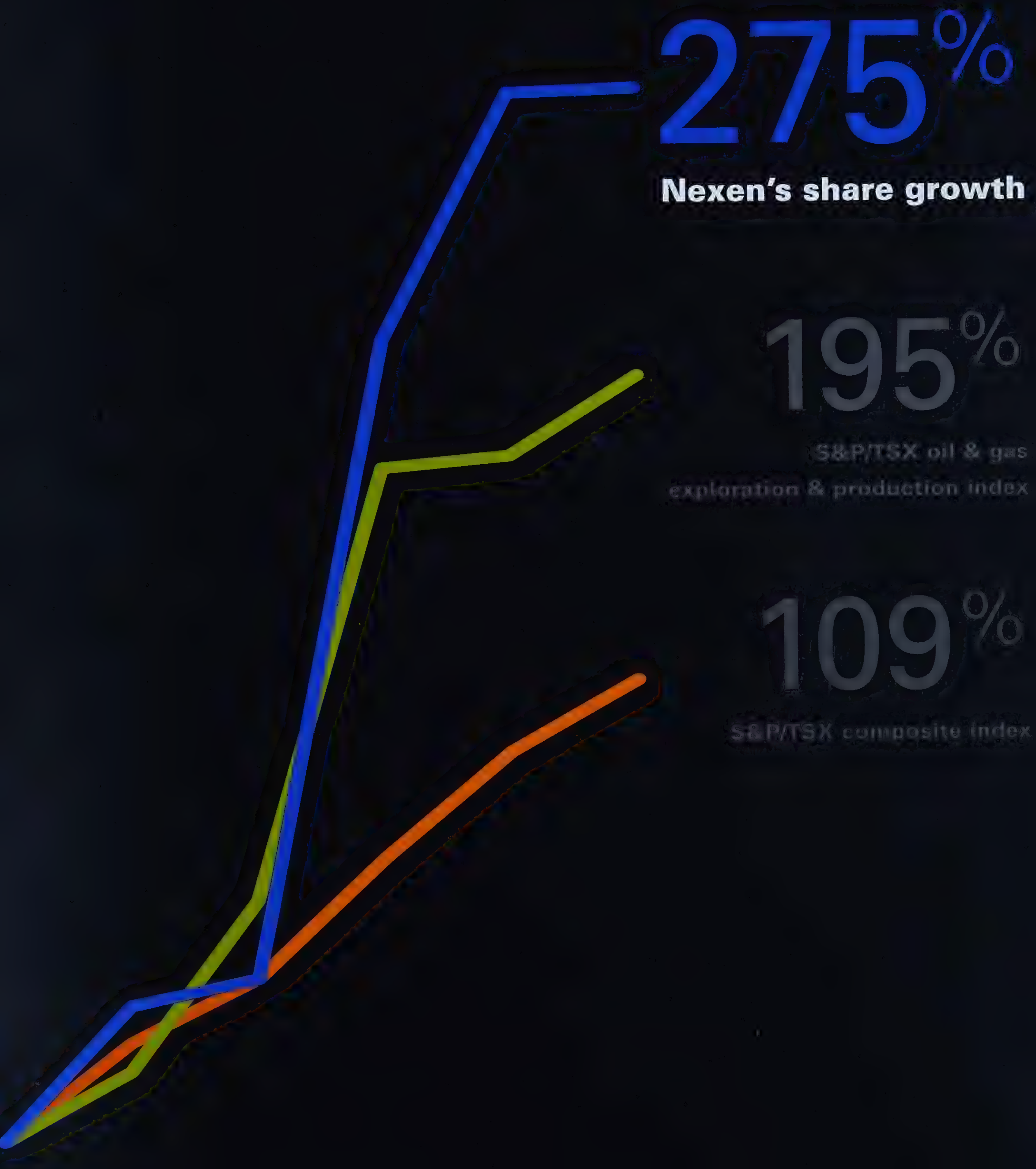
why invest in Nexen

Whether you are a shareholder or an employee, you invest in Nexen because we're creating value. Over the past five years, our share price increased **275%**, outperforming many of our peers and several major indices. How do we do it? We look beyond today and capture early positions in oil sands, CBM and shale gas lands. We rise to the challenge and turn mega projects, like Yemen and Buzzard, into legacies. And we do the right things for the right reasons and never compromise safety, ethics, or the environment. See the value and join us in an exciting future as we bring on **what's next.**

Did you know we've been profitable ever year, except one, in our 37-year history? Learn more about Nexen as a great long-term investment at ***www.nexeninc.com/reports/A3.asp***



5-year share performance



what drives our success

Long Lake—Steam Generator

we commit to powerful strategies

Studies show that applying new technology could increase worldwide supply just as much as successful exploration. Quantum results occur when that technology is applied to a critical mass. Take Long Lake. Years ago we identified hurdles in developing oil sands, accumulated significant inventory and formed a strategy that disrupts conventional wisdom. The patented process substantially reduces the need to purchase natural gas, resulting in an expected $10/bbl cost advantage. Apply this to additional phases, and the rewards are massive. With significant CBM, shale gas and deep-water inventory, we're planning strategies for **what's next**.

Did you know Long Lake is named after a nearby lake, which is more round than long? Learn more about the project at ***www.nexeninc.com/reports/A4.asp***

Leyla Rojas, *Engineer*

strategy

up to 9

more phases of Long Lake

Phase 1 of Long Lake will only develop about 10% of our total oil sands leases. We will continue to develop this asset in phases, leveraging our unique technology to generate tremendous value.

we explore a world of opportunities

Our opportunity inventory is simply unbeatable in both quality and size. Built with foresight, it is global and diverse, making us more sustainable in changing market conditions. Here in Canada, we have billions of barrels of oil sands inventory plus significant land positions with CBM and shale gas potential. Internationally, we have thousands of unexplored acres in the North Sea and the Gulf of Mexico. Now our job is to turn these opportunities into value-generating projects. In 2008, we'll bring on Long Lake and Ettrick, and drill up to 11 exploration wells worldwide. Any one of these wells could be **what's next.**

Did you know we employ about 3,500 people worldwide and opened an office in Norway? Learn more about our global operations at ***www.nexeninc.com/reports/A5.asp***

Canadian Rockies

inventory

top 10

deep-water leaseholder in Gulf of Mexico

We are constantly investing in our future. In 2007, we acquired deep-water acreage in the Gulf of Mexico and now hold about 200 blocks. With several drill-ready prospects, we're excited to discover what's next.

ulf of Mexico

we develop world-class assets

Globally speaking, we are a small company with big company assets. And in this industry, size matters. Oil and gas is largely a fixed cost business—so larger fields and volumes yield lower unit capital and operating costs. Worldwide, there are just over 100 fields producing more than 100,000 boe/d. Buzzard in the North Sea and Masila in Yemen are part of this elite group. Next is Usan, offshore Nigeria, expected to produce around 180,000 boe/d (36,000 boe/d net to us). Long Lake in Canada and Knotty Head in the Gulf of Mexico could soon belong here too. With such exciting mega projects, we can't wait to develop **what's next**.

Matt Staines, *Project Engineer*

Did you know our marketing group sells our Buzzard and Masila crude, and power too? Learn more about our dynamic marketing business at ***www.nexeninc.com/reports/A6.asp***

projects

1.6 billion

our Buzzard pre-tax cash flow in 2007

We transform possibilities into exciting projects. Buzzard came on stream in 2007 generating significant value for shareholders and winning Energy Engineering Project of the Year. We're proud to be part of this legacy.

Buzzard

we build sustainable businesses

We are committed to exemplary corporate governance, environmental and social responsibility, and the health and safety of our workforce. We believe, over the long term, companies that steward to such business practices will be more sustainable and will outperform those with narrower priorities. But don't just take our word—see for yourself. We are recognized as a leader in corporate governance and sustainability reporting, winning awards for both. For the first time ever, our Scott/Telford offshore UK operations went two years without a lost-time injury. And we've been included in the Dow Jones Sustainability Index for the past seven years. Living our values brings value today and to **what's next.**

Did you know Soderglen Wind Farm produces enough green energy to power about 25,000 homes? Learn more about sustainability at Nexen by visiting ***www.nexeninc.com/reports/A7.asp***

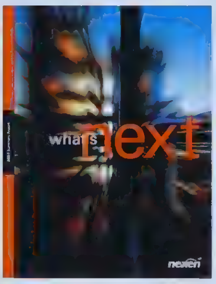
stewardship

top 50 employer in Canada

We value our employees and they value us. For five of the past six years, we have been named one of the 50 best employers in Canada. Join us and see why.

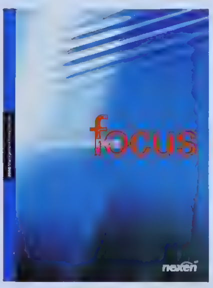
annual publications

The following reports are available on our website at **www.nexeninc.com/investors** and hard copies may be ordered online or by calling **403.699.5931**.

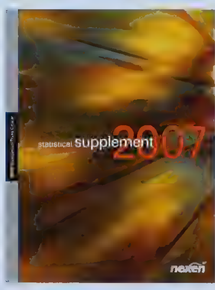


2007 Summary Report

2007 Sustainability Report
Available June 2008



2008 Management Proxy Circular



2007 Statistical Supplement

awards and recognition

50 Best Employers in Canada
Hewitt Associates

Top 25 Employers in Alberta
Mediacorp Canada Inc.

Energy Engineering Project of the Year—Buzzard
Platts Global Energy Awards

Dow Jones Sustainability Index
Recognized as a global sustainability leader by being included on the index for seven years in a row.

Sustainability Report Award
Oilweek/ATB Financial Annual Report Awards

National Award in Governance Private Sector
The Conference Board of Canada

North America's Best: IR Website, Disclosure Procedures and Governance Practices
IR Global Rankings

#1 of Top 25 Boards in Canada
Canadian Business Magazine

Excellence for Electronic Disclosure
Canadian Institute of Chartered Accountants

Excellence in Corporate Governance Disclosure—Honourable Mention
Canadian Institute of Chartered Accountants

Governance Gavel Award for Director Disclosure—Honourable Mention
Canadian Coalition for Good Governance

Top 50 Corporate Citizens
Corporate Knights Magazine

Global 100 List
For the most sustainable international corporations.
Corporate Knights/Innovest

Corporate Social Responsibility
Third out of 10, Oil and Gas Category
Globe and Mail and Jantzi Research

Honorary Bachelor of Applied Technology Degree
Charlie Fischer,
President and CEO
Southern Alberta Institute of Technology

Energy Executive of the Year
Marvin Romanow,
Executive VP and CFO
Petroleum Economist Magazine

CFO of the Year
Marvin Romanow,
Executive VP and CFO
PricewaterhouseCoopers LLP, Financial Executives International Canada, and Caldwell Partners International

Honorary Doctorate of Laws Degree
Dr. Randy Gossen,
VP, Health, Safety, Environment and Social Responsibility
University of Calgary

Order of the British Empire
Paul Doble,
Buzzard General Manager

Two Year LTI (Lost-Time Injury) Free Award—Scott Platform
Production Services Network

Top Benefit and Pension Plans in Canada
Benefits Canada Magazine

Senator Thelma Chalifoux Award
For commitment to Aboriginal student success.
Northern Alberta Institute of Technology

Woodlands County Business Award
For assisting the Fort Assiniboine community towards sustainability.

Thanks a Million Award
For raising over $1 million
United Way of Calgary

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of

THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2007

Commission File Number 1-6702

NEXEN INC.

Incorporated under the Laws of Canada

nexen

98-6000202

(I.R.S. Employer Identification No.)

801 - 7th Avenue S.W.

Calgary, Alberta, Canada T2P 3P7

Telephone: (403) 699-4000

Web site: www.nexeninc.com

Securities registered pursuant to Section 12(b) of the Act:

Title	Exchange Registered On
Common shares, no par value	The New York Stock Exchange The Toronto Stock Exchange
Subordinated Securities, due 2043	The New York Stock Exchange The Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes _√_ No ___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ___ No _√_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

Yes _√_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _√_

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer.

Large accelerated filer _√_ Accelerated filer ___ Non-accelerated filer ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No _√_

On June 30, 2007, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $17 billion based on the Toronto Stock Exchange closing price on that date. On January 31, 2008, there were 528,502,991 common shares issued and outstanding.

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Special Note to Canadian Investors—see page 76
Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format. Volumes and reserves include Syncrude operations unless otherwise stated.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

/d	=	per day	mboe	=	thousand barrels of oil equivalent
bbl	=	barrel	mmboe	=	million barrels of oil equivalent
mbbls	=	thousand barrels	mcf	=	thousand cubic feet
mmbbls	=	million barrels	mmcf	=	million cubic feet
mmbtu	=	million British thermal units	bcf	=	billion cubic feet
km	=	kilometre	WTI	=	West Texas Intermediate
MW	=	megawatt	NGL	=	natural gas liquid

In this 10-K, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf/1bbl). This conversion may be misleading, particularly if used in isolation, as the 6mcf/1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

The noon-day Canadian to US dollar exchange rates for Cdn $1.00, as reported by the Bank of Canada, were:

(US$)	December 31	Average	High	Low
2003	0.7738	0.7135	0.7738	0.6350
2004	0.8308	0.7683	0.8493	0.7159
2005	0.8577	0.8253	0.8690	0.7872
2006	0.8581	0.8818	0.9099	0.8528
2007	1.0120	0.9304	1.0905	0.8437

On January 31, 2008, the noon-day exchange rate was US $0.9978 for Cdn $1.00.

Electronic copies of our filings with the Securities Exchange Commission (SEC) and the Ontario Securities Commission (OSC) (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, on request, by contacting our investor relations department at 403.699.5931. As soon as reasonably practicable, our filings are made available on our website once they are electronically filed with the SEC and/or the OSC. Alternatively, the SEC and the OSC each maintain a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the OSC.

global **operations**

In 2007, we added value by bringing Buzzard on stream. Our Long Lake oil sands project is next, expected on stream in mid 2008.

PART I
ITEMS 1 AND 2. BUSINESS AND PROPERTIES

ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 when Occidental Petroleum Corporation (Occidental) combined their Canadian crude oil, natural gas, sulphur and chemical operations into one company. We've grown from producing 10,700 boe/d before royalties with revenues of $26 million in 1971, to producing 253,600 boe/d before royalties (including Syncrude production) and revenues of $5.6 billion in 2007. We achieved this growth through exploration success and strategic acquisitions. Operating for more than 35 years, we have been profitable every year, except one, and have been paying quarterly dividends consecutively since 1975.

In the 1970s, we expanded our western Canadian assets and entered the US Gulf of Mexico. We finished this decade with production of approximately 11,000 boe/d before royalties and revenues of $126 million.

Buzzard produced first oil early in the year and we made significant construction and commissioning progress at Long Lake.

In the 1980s, we continued to expand in western Canada and the Gulf of Mexico through acquisitions. Acquiring Canada-Cities Services in 1983 doubled our size and included an interest in the Syncrude Joint Venture, our entry into the Athabasca oil sands. We finished this decade with production of approximately 68,600 boe/d before royalties and revenues of $591 million.

In the 1990s, we had two defining events: discovering oil on the Masila block in Yemen and acquiring Wascana Energy Inc. The first of 17 fields at Masila was discovered in 1991. Since start up in 1993, Masila has produced almost a billion barrels of crude oil. Our 1997 purchase of Wascana Energy Inc. almost tripled our Canadian production. In 1998, we entered Australia with an interest in the offshore Buffalo field and Nigeria as the operator of the Ejulebe field. Also in 1998, we discovered Ukot on Block OPL-222, offshore Nigeria. We finished this decade with production of approximately 239,200 boe/d before royalties and revenues of $1.7 billion.

So far in the 21st century, we have made a number of discoveries, two strategic acquisitions and completed non-core asset divestiture programs. In 2000, we discovered Gunnison in the deep-water Gulf of Mexico and Guando in Colombia. We joined with Ontario Teachers' Pension Plan Board (Teachers) to acquire Occidental's remaining 29% interest in us. Teachers purchased 20.2 million common shares. We repurchased the remaining 20 million common shares for $605 million, which would have had a value of almost $2.6 billion at the end of 2007. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations and we changed our name from Canadian Occidental Petroleum Ltd. to Nexen Inc. In 2001, we discovered Aspen in the deep-water Gulf of Mexico and signed a joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake in the Athabasca oil sands. In 2002, we discovered Usan, the second discovery on OPL-222, offshore Nigeria. In late 2003, we discovered two fields on Block 51 in Yemen.

In 2004, we acquired properties in the UK North Sea, providing us with operatorship of the Buzzard discovery, the producing Scott and Telford fields and 700,000 exploration acres. In 2005, we completed non-core asset divestiture programs by selling Canadian conventional oil and gas properties producing approximately 18,300 boe/d before royalties and by monetizing 39% of our chemical business through the initial public offering of the Canexus Income Fund. We also made a potentially significant discovery in the Gulf of Mexico at Knotty Head and commenced commercial development of our first coalbed methane (CBM) project in the Fort Assiniboine area in western Canada. In 2006, we completed major development projects at Buzzard in the North Sea and the Syncrude Stage 3 expansion in the Athabasca oil sands. In 2007, Buzzard produced first oil early in the year and we made significant construction and commissioning progress at our Long Lake Project. At Long Lake, SAGD steam injection began in the second half of 2007 and the upgrader is scheduled to start up in mid 2008. We also significantly added to our inventory of exploration prospects during the year by securing new Gulf of Mexico deepwater leases, obtaining exploration licences offshore Norway and acquiring additional shale gas opportunities in Canada. Our portfolio of assets, combined with talented people and an active exploration program, are expected to provide future growth for our company.

For financial reporting purposes, we report on four main segments:

- oil and gas;
- Syncrude;
- energy marketing; and
- chemicals.

Our oil and gas operations are broken down geographically into the UK North Sea, US Gulf of Mexico, Canada, Yemen and Other International (currently Colombia, offshore West Africa and Norway). Results from our Long Lake Project are included in Canada. Syncrude is our 7.23% interest in the Syncrude Joint Venture. Energy marketing includes our growing crude oil, natural gas, natural gas liquids, ethanol and power marketing business in North America, Europe and Asia.

Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda and chlorine through the Canexus Limited Partnership.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 20 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

STRATEGY

Our goal is to grow long-term value for our shareholders responsibly. Key drivers to growing value include increasing reserves, production, cash flow and net income on a cost-effective basis over the long term. We believe in developing a competitive advantage where possible, to assist in generating opportunities for long-term success in our ever-evolving industry. As conventional basins in North America mature, we have developed specific capabilities in oil sands, CBM, deep-water technology and international experience. These skills enable us to focus on specific types of projects, as we transition toward major projects in established basins, exploration in less mature basins and exploitation of unconventional resources.

Today, we are building new sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:

- We have access to resource in our key areas that creates future opportunities. Our Long Lake Project is developing only 10% of our oil sands leases in the Athabasca oil sands and we hold unexplored acreage in the Gulf of Mexico, the North Sea, western Canada and elsewhere;
- We are successful explorers with significant discoveries at Knotty Head and Vicksburg in the Gulf of Mexico, Golden Eagle in the UK North Sea and at Usan, offshore Nigeria;
- We are skilled project managers with major development projects, proven by bringing Buzzard on stream in early 2007;
- We are innovative in our application of technology. Long Lake is expected to be the first oil sands project to use gasification technology to significantly reduce the cost of producing bitumen and we are advancing new techniques for unconventional production of CBM and enhanced heavy oil recovery in western Canada;
- We are an international operator with a proven track record of successful business ventures in Yemen, the United Kingdom, Nigeria, Colombia and Australia; and
- From time to time, we supplement our growth with acquisitions, such as our strategic entry into the UK North Sea in 2004.

The location and scale of our operations often result in: 1) an extended period of time from the capture of opportunities to first production and 2) non-linear, year-over-year growth in reserves and production. Significant up-front capital investment is often required prior to realizing production and free cash flows. We fund this investment by maximizing cash flow from our producing assets, issuing long-term debt and/or equity and selling non-core assets into attractive markets.

Our long-term strategy is to build capacity by ensuring we have a sufficient inventory of opportunities for future growth. We have a number of opportunities expected to provide production growth and create shareholder value well into the next decade. They include undeveloped discoveries at Knotty Head and Vicksburg in the Gulf of Mexico, Usan and Ukot offshore Nigeria, various discoveries in the UK North Sea, together with development of CBM, shale gas and additional oil sands leases in Canada.

Our goal is to grow long-term value responsibly for our shareholders by building sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa.

In creating sustainable businesses, we are committed to good corporate governance practices and social responsibility. We believe that over the long term, companies that follow sustainable business practices outperform those with narrower priorities. We foster dialogue with stakeholders about our operational opportunities and challenges, from exploration to production to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing multiple, and sometimes conflicting goals.

UNDERSTANDING THE OIL AND GAS BUSINESS

The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price products command in the market based on quality and marketing efforts. Our goal is to extract the maximum value from each barrel of oil equivalent, so every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices.

The prices we receive for our oil and gas products are mainly determined by volatile global crude oil and natural gas markets. With many alternative customers, the loss of any one customer is not expected to have a significantly adverse effect on the price of our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products can fluctuate season to season, which impacts price. In particular, heavy oil is generally in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating. We manage our operations on a country-by-country basis, reflecting differences in the regulatory and competitive environments and risk factors associated with each country.

OIL AND GAS OPERATIONS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, western Canada, Yemen, Colombia, offshore West Africa and Norway. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

In this Form 10-K, we provide estimates of remaining quantities of proved oil and gas reserves for our various properties. Such estimates are internally prepared. We had 98% of our oil and gas reserves before royalties (98% after royalties) and 100% of our Syncrude reserves before royalties (100% after royalties) assessed (either evaluated or audited as described on page 21) by independent reserves consultants. Their assessments are performed at varying levels of property aggregation, and we work with them to reconcile the differences on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively; however, we believe such differences are not material relative to our total proved reserves. Refer to the section on Critical Accounting Estimates—Oil and Gas Accounting—Reserves Determination on page 68 for a description of our reserves process, and to the section on Reserves, Production and Related Information on page 16 for a description of the nature and scope of the independent assessments performed and the results thereof.

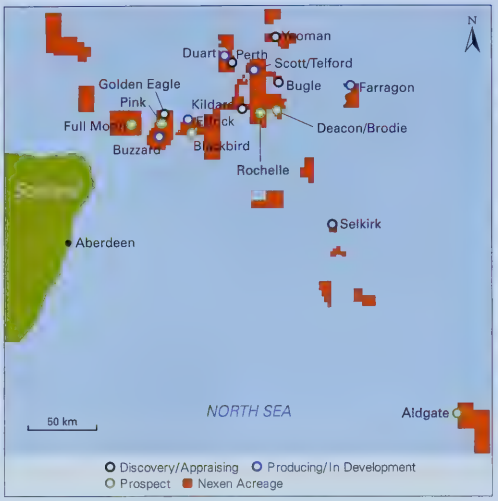
North Sea—United Kingdom (UK)

The UK North Sea is a key producing area. In 2004, we acquired a 43.2% operated interest in the Buzzard development, a 41% operated interest in the Scott field, a 54.3% operated interest in the Telford field, the Scott production platform, interests in several satellite discoveries and more than 700,000 net undeveloped exploration acres for US$2.1 billion. This acquisition established us as a significant regional player with concentrated assets, infrastructure and exploration and development potential for future growth. It added high-margin reserves and production, diversified our worldwide portfolio by adding strong assets in a stable jurisdiction, and complemented our other longer cycle-time projects.

Our UK strategy is to grow and sustain our existing North Sea production and capture new production hubs with exploration and exploitation opportunities near existing infrastructure.

We have a number of exploitation opportunities in our existing fields and smaller undeveloped discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford, Buzzard or Ettrick. As a result, new discoveries can be tied-in quickly.

During the year, we produced 84,000 boe/d before royalties (84,000 after royalties) in the UK, which was approximately one-third of our total production. At year end, our UK proved oil and gas reserves of 207 mmboe before royalties (207 after royalties) represented about 20% of our total proved oil and gas and Syncrude reserves.



Buzzard

Buzzard is the largest discovery in the UK North Sea in the past ten years. It was discovered in 2001 and began producing January 7, 2007. Development of this discovery was on time and on budget.

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. The facilities can process at least 200,000 bbls/d of oil and 60 mmcf/d of gas. Development drilling has resulted in more well-to-well variability in the concentration of hydrogen sulphide than originally expected. To address this, we plan to construct a fourth platform with production sweetening facilities to handle higher levels of hydrogen sulphide. We believe existing equipment and processes can manage current hydrogen sulphide levels and maintain current production deliverability until the additional equipment is commissioned in 2010.

During the year, we produced 84,000 boe/d in the UK, which was approximately one-third of our total production.

Oil from Buzzard is exported via the Forties pipeline to the Grangemouth refinery in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

We expect to produce Buzzard through 27 production wells and maintain reservoir pressure through an active water-flood program. In 2008, we plan to invest $255 million to drill five production wells, two sidetracks, one water injector and progress work on the fourth platform.

Scott/Telford

Scott and Telford are producing fields with additional exploitation opportunities and both tie back to the Scott platform. Scott was discovered in 1987 and began producing in September 1993, while Telford was discovered in 1991 and came on stream in 1996. In 2007, we increased our interests in these fields and at the end of the year, we have a 41.9% working interest in the Scott platform and field, and a 71.75% working interest in Telford. In 2007, our share of production from these fields was approximately 16,500 boe/d. The production is royalty-free, around 90% oil and produced through numerous subsea wells. Oil is delivered to the Grangemouth refinery in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in northeast Scotland. In recent years, the Scott platform underwent a significant maintenance turnaround and facilities upgrade to improve reliability and extend facility life.

Ettrick

We are progressing development of the Ettrick field and we expect it on stream mid 2008. We expect to ramp up to production of approximately 30,000 boe/d gross by the end of the year. Development includes three subsea production wells and one water injector tied back to a leased floating production, storage and off-loading vessel (FPSO). The FPSO is designed to handle 30,000 bbls/d of oil, 35 mmcf/d of gas and to re-inject 55,000 bbls/d of water. Our share of full-cycle development costs is estimated at $460 million. We operate Ettrick with an 80% working interest.

Other

Our 2004 UK acquisition included a non-operated interest in Farragon, a small satellite discovery, which was brought on stream in late 2005. In 2007, the non-operated Duart field was brought on stream and began producing oil from a single well tied back to the Tartan platform. Our share of production from these non-operated properties was 3,300 boe/d before royalties (3,300 after royalties) in 2007.

Exploration and Undeveloped Assets

In 2007, we discovered hydrocarbons at Golden Eagle and then drilled a successful sidetrack to appraise the accumulation. We are currently evaluating development options and expect to sanction development in 2008. In 2007, we also drilled a successful exploration well at Kildare, and plan to follow up the discovery with an appraisal well. We also completed appraisal of the Selkirk prospect with favourable results. We have a number of discoveries on operated blocks near Scott, Buzzard and third-party facilities as follows:

Field	Interest (%)	Operator Status	Comments
Black Horse	60	operated	discovery near Scott; evaluating development alternatives
Bugle	41	operated	discovery near Scott; appraisal well underway
Dolphin	42	operated	discovery near Scott; evaluating development alternatives
Golden Eagle	34	operated	discovery near Ettrick; evaluating development alternatives
Kildare	50	operated	discovery near Scott; appraisal well planned for 2008
Perth	42	operated	discovery near Scott; evaluating development alternatives
Polecat	40	operated	discovery near Buzzard; evaluating appraisal options
Selkirk	38	operated	discovery near Buzzard; evaluating development alternatives
Yeoman	50	operated	discovery near Scott; evaluating development alternatives

In 2007, we drilled unsuccessful exploration wells at Guinea, Dee and Stag. The three wells encountered non-commercial quantities of hydrocarbons and were abandoned. In 2008, we expect to drill six exploration and two appraisal wells. We have secured drilling rigs for all of our 2008 North Sea exploration and development program.

We have also begun assessing emerging CBM opportunities in the UK. In 2006, we acquired an 80% working interest in one opportunity and have drilled two successful exploration wells so far. Both encountered coal seams as expected and are being monitored through ongoing production testing. In another CBM opportunity, we drilled two unsuccessful exploration wells in 2007. We plan to continue assessing CBM potential in the UK with additional exploratory wells in 2008.

Fiscal Terms

UK fiscal terms are favourable. New discoveries pay no royalties and result in cash netbacks that are higher than our company average. Scott is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which isn't expected before 2010. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance. PRT is applicable to fields receiving development consent prior to March 1993. Buzzard, Ettrick, Farragon, Duart and Telford are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate on oil and gas activities is 30% of taxable income and is also subject to a 20% supplemental charge. The amount and timing of income taxes payable depends on many factors including price, production, capital investment levels and available tax losses.

Gulf of Mexico—United States (US)

The Gulf of Mexico is an integral part of our growth strategy. Large discoveries, relatively high success rates, expanding production infrastructure and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. While costs of deep-water exploration are high relative to other basins, deep-water prospects generally have multiple sands and high production rates—factors which reduce risk and improve economics. Technology to find, drill, and develop discoveries is rapidly progressing and becoming more cost effective. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time.

We are evaluating development options for Vicksburg, South Marsh Island 257 and Mississippi Canyon 72 and look forward to developing Longhorn in 2008.

Our strategy in the Gulf is to explore for new reserves, exploit our existing asset base and acquire assets with upside potential. We focus our exploration program on three strategic play types:

- deep-water prospects near existing infrastructure;
- deep-water, Miocene and Lower Tertiary sub-salt plays with the potential to become new core areas; and
- deep-water, Norphlet targets in the eastern Gulf of Mexico.

These plays are relatively under-explored, hold potential for large discoveries and have attractive fiscal terms. The relatively shorter cycle-times for deep-water prospects near

infrastructure complement the longer cycle-times for deep-water sub-salt and Norphlet plays. Although competition in the Gulf is strong, we have built a large inventory of deep-water acreage and are now the eighth largest leaseholder in the deep-water.

In 2007, we invested $793 million on exploration, development and acquisitions in the Gulf. This resulted in three discoveries at Desoto Canyon Block 353 (Vicksburg), South Marsh Island 257 and Mississippi Canyon 72 as well as a successful appraisal well at Longhorn. Additionally, we acquired three producing deep-water fields and enhanced our deep-water acreage position. However, some of our development drilling in 2007 did not meet expectations. In 2008, we plan to invest approximately $390 million in the Gulf to further our growth strategies. This includes development of our Longhorn discovery, drilling of proved undeveloped reserves, exploration drilling and land acquisition.

Exploration and Undeveloped Assets

Given our drilling success in 2007, we are evaluating development options for our discoveries at Vicksburg, South Marsh Island 257 and Mississippi Canyon 72 and look forward to developing the Longhorn discovery in 2008. Our undeveloped deep-water discoveries include:

Well	Interest (%)	Operator Status	Comments
Longhorn	25	non-operated	sanctioned; production expected 2009
Tobago	10	non-operated	sanctioned; production expected 2009
Knotty Head	25	operated	discovery; further appraisal required
Vicksburg	25	non-operated	discovery; further appraisal required
South Marsh Island 257	35	non-operated	discovery; production expected 2008
Mississippi Canyon 72	33	non-operated	discovery; production expected 2008

During the year, we drilled ten exploratory dry holes on the shelf. We also converted our interests in Anduin and Great White West to overriding royalty interests to accelerate monetization of the reserves with no further capital investment. We acquired deep-water acreage during the year and hold approximately 200 blocks and expect this acreage and future exploration opportunities to position us well for continued growth. In 2008, we plan to drill seven exploration and appraisal wells and have secured drilling rigs for more than half of the wells. Access to deep-water rigs remains limited. To explore our inventory and evaluate existing discoveries, we have secured two new-build dynamically-positioned fifth-generation semi-submersible drilling rigs. We will have access to each rig for at least two years. We expect the first rig to be available mid 2009, followed by the second rig in 2010.

US Production

	2007		2006		2005	
(mboe/d)	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Deep-water	19.4	17.4	19.6	17.5	24.0	21.5
Shelf	13.8	11.5	15.9	13.2	17.6	14.6
Total	**33.2**	**28.9**	**35.5**	**30.7**	**41.6**	**36.1**

At year end, proved reserves of 62 mmboe before royalties (53 after royalties) in the Gulf of Mexico represented about 6% of our total proved oil and gas and Syncrude reserves. Our Gulf production and reserves are primarily concentrated in four deep-water and five shallow-water (shelf) areas. We operate most of this production.

Deep-water

Most of our deep-water production comes from our 100%-operated Aspen field and our 30% non-operated Gunnison field. The remaining comes from our 50% non-operated Wrigley field and three 100%-operated properties purchased in 2007.

Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the Shell-operated Bullwinkle platform 16 miles away and began producing in December 2002. Our share of 2007 production before royalties was approximately 10,400 boe/d (9,500 after royalties).

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in December 2003 through our truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas. Our Gunnison SPAR facility has excess capacity, leaving room for growth from regional exploration and processing of third-party volumes. We achieved payout on Gunnison in December 2005, just two years after first production. In 2007, our share of production before royalties was approximately 7,000 boe/d (6,200 after royalties).

Wrigley is on Mississippi Canyon Block 506 in 3,300 feet of water. The project consists of a single subsea well tied back to the Shell-operated Cognac platform 17 miles away. Wrigley began gas production in July 2007 and our share before royalties in 2007 was approximately 1,100 boe/d (1,000 after royalties).

The three new deep-water fields acquired in 2007 are on Garden Banks Block 205, Green Canyon 137 and Green Canyon 6/50—all in water depths between 700 and 1,100 feet. In 2008, we plan to drill a development well at Green Canyon 6/50.

Shelf

Our shelf producing assets are offshore Louisiana, primarily in five 100%-owned field areas: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 302/321/339/340, and Vermilion 76 (consisting of Blocks 65, 66 and 67). We continue to exploit these assets and look for other shelf opportunities. Most of our 2007 shelf activities focused on development drilling at Eugene Island 258/259, Eugene Island 295 and Vermillion 340.

Fiscal Terms

In 2007, royalty rates on our US production averaged 16.5% for shelf volumes and 10.6% for deep-water volumes. The US government has increased royalty rates from 12.5% to 16.7% for new deep-water leases awarded after July 2007. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmboe of production. However, we may be subject to royalties at Gunnison if annual commodity prices are higher than threshold prices set by the US Department of the Interior's Minerals Management Service (MMS). The oil and gas industry is currently litigating the enforceability of these price thresholds. In October 2007, a US District Court ruled that the price thresholds were unenforceable. The MMS has since appealed this ruling and a decision is expected by the end of 2008. In 2007, commodity prices exceeded these thresholds and we were assessed a royalty at Gunnison of 12.5% by the MMS. If the litigation is not successful, royalties that we have accrued on our Gunnison production will be payable. Our Aspen field is not subject to the minimum price threshold. Although several bills were recently proposed burdening leases awarded in 1998 and 1999 with royalties or severance taxes, no such legislation was passed by US Congress.

US taxable income is subject to federal income tax of 35% and state taxes ranging from 0% to 12%.

Canada

Our strategy in Canada is two fold: 1) develop unconventional resource opportunities (oil sands, CBM and shale gas) and 2) maximize value from our established operations through continued conventional development and enhanced recovery methods. In 2007, we produced 36,800 boe/d before royalties (29,700 after royalties) in Canada, which was approximately 14% of our total production including Syncrude. At year end 2007, Canadian proved reserves (including bitumen and excluding Syncrude) of 386 mmboe before royalties (334 after royalties) were approximately 36% of our total proved oil and gas and Syncrude reserves.

Our Canadian conventional assets include heavy oil production in east-central Alberta and west-central Saskatchewan,

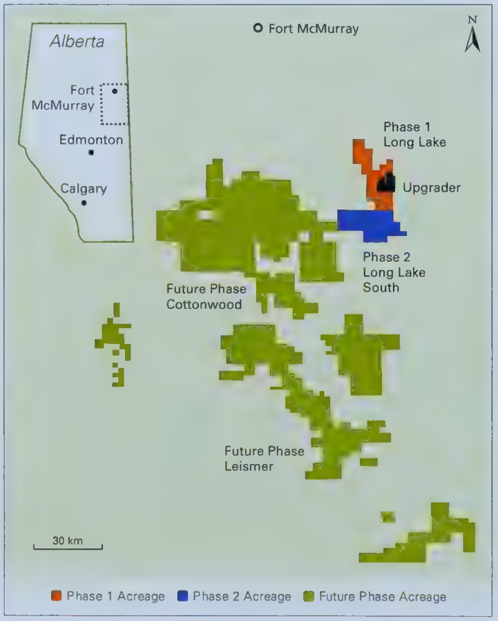
and natural gas near Calgary and in southern Alberta and Saskatchewan. We operate most of our producing properties and hold almost one million net acres of undeveloped land across western Canada. These assets provide predictable production volumes and earnings while we advance the following initiatives for future growth:

- Athabasca oil sands—to produce and upgrade bitumen into synthetic crude;
- enhanced oil recovery (EOR)—to increase recovery in our heavy oil fields;
- coalbed methane (CBM)—to extract natural gas primarily from Upper Mannville and Horseshoe Canyon coals; and
- shale gas—to evaluate natural gas from organic shales.

In 2007, we invested $1,505 million in Canada; $1,380 million into these growth initiatives. With the expected completion of Long Lake Phase 1 in the Athabasca oil sands, we plan to reduce our capital investment in 2008 to approximately $770 million. Our 2008 capital programs will focus on completing Phase 1 and work towards sanctioning Phase 2 at Long Lake, advance our CBM strategies and evaluate the potential of shale gas.

Athabasca Oil Sands

The Athabasca oil sands in northeast Alberta is a key growth area for Nexen. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our Long Lake Project involves integrating steam-assisted-gravity-drainage (SAGD) bitumen production with field upgrading technology to produce a premium synthetic crude and synthetic gas, which significantly reduces our need to purchase natural gas for operations. We also have a 7.23% investment in the Syncrude oil sands mining operation.



Long Lake Project

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake lease using SAGD for bitumen production and proprietary OrCrude™ technology for our first stage of upgrading. OPTI has the exclusive Canadian license for the OrCrude™ technology. We acquired the exclusive right to use this technology with OPTI within approximately 100 miles of Long Lake, and the right to use the technology independently elsewhere in the world.

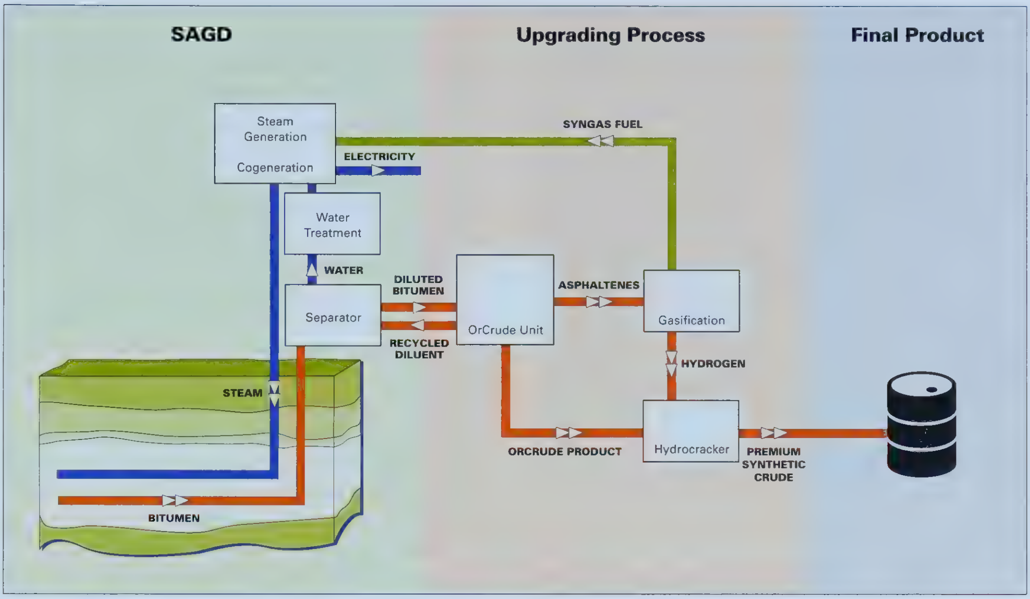
We operate the Long Lake bitumen extraction process and are responsible for constructing, developing and operating the SAGD project. OPTI is responsible for designing, constructing and operating the upgrader. We share equally in all project reserves, production, operating and capital costs.

SAGD and Upgrader Integration

SAGD involves drilling two parallel horizontal wells, generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude is upgraded to light (39° API) premium synthetic sweet crude oil, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel for generating steam and as a source of hydrogen for the hydrocracking process. The gas will also be burned in a cogeneration plant to produce electricity to be used on-site and sold to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is about 90% compared to 75% for a typical bitumen-fed coker, which we expect will provide us with an approximate $10/bbl operating cost advantage.

Our Strategic Advantage

Our integrated SAGD and upgrading process addresses three main economic hurdles of SAGD bitumen production: 1) the high cost of natural gas; 2) the cost and availability of diluent; and 3) the realized price of bitumen. With synthetic gas from the asphaltenes as fuel, we need to purchase very little additional natural gas. With the upgrading facilities on site, expensive diluent is not required to transport the bitumen to market. And, by upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands light-sweet crude oil premium pricing.



Project Milestones and Costs

The Long Lake Project received regulatory approval in 2003 and Nexen board approval in 2004. Field construction of the SAGD and upgrader facilities began in 2004. In 2006, we substantially completed module and site construction of the SAGD facilities. In 2007, we began injecting steam in all 10 well pads. The first six months of steam injection largely involves heating the reservoir, followed up by a ramp-up of bitumen production to peak rates over 12 to 24 months. At the start of production, steam-to-oil ratios will be high but will decline as bitumen production ramps up to our target rates. Depending on start up issues and any related facility down time, we expect bitumen production before royalties to reach between 35,000 and 45,000 bbls/d (between 17,500 and 22,500 bbls/d net to our share) by the end of 2008, with a steam-to-oil ratio of between 3.5 and 4.0. We expect the steam-to-oil ratio to average approximately 3.0 over the long-term.

Upgrader module fabrication is complete and all modules are on site. Construction of the upgrader was approximately 97% complete at year end and start up is scheduled for mid 2008. Peak output of premium synthetic crude oil is expected within 12 to 18 months of upgrader start up and we expect to exit 2008 with synthetic production rates between 30,000 and 40,000 bbls/d (between 15,000 and 20,000 bbls/d net to our share). Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (30,000 bbls/d net to our share) of premium synthetic crude, which we expect to reach in 2009. We expect to maintain production over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

In 2008, we will bring on Long Lake and expect bitumen production to reach between 35,000 and 45,000 bbls/d (17,500 and 22,500 bbls/d net to us).

In 2007, we invested $1,025 million at Long Lake Phase 1. Long Lake's total capital costs have increased since project sanctioning due to design enhancements and industry cost pressures. When our board sanctioned the project in February 2004, capital costs were estimated at $3.4 billion ($1.7 billion net). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to ensure reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million ($49 million net). In early 2006, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million ($180 million net). These scope changes increased the estimated project cost to $3.8 billion ($1.9 billion net). Since then, high activity in the oil sands has placed ongoing cost pressures on labour and services. As well, lower than anticipated labour productivity has required a larger workforce to maintain progress. As a result, the projected costs of Long Lake have increased from $3.8 billion to between $5.8 billion and $6.1 billion (between $2.9 billion and $3.05 billion net to us). Despite capital cost increases, we still expect to achieve good economic returns which benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average about $17/bbl, substantially

lower than coking or other upgrading processes. We expect ongoing capital to average between $3/bbl and $4/bbl. The full-cycle capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

Future Phases

We have approximately 249,000 net acres of bitumen-prone lands in the Athabasca region, with plans to acquire more. We plan to continue developing our bitumen lands in phases using our integrated upgrading strategy. In 2005, we announced our plan to duplicate Long Lake by developing Phase 2. In 2007, we invested $114 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for these phases.

During 2007, the Alberta government proposed increases to oil sands royalty rates and implemented climate change legislation. The federal government also announced climate change proposals; however, legislation has not been drafted. Due to this regulatory uncertainty, we are delaying certain planned expenditures on Phase 2. Phase 2 will be followed by additional phases every three or four years. Each phase will leverage the knowledge and experience gained from successfully developing Long Lake and subsequent projects will be similar in size and design. By keeping the core team in place and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

Reserves Recognition

Under SEC rules and regulations, we are required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce and sell. The economic recoverability of bitumen reserves is sensitive to natural gas prices, diluent costs and light/heavy differentials, risks that our integrated project has been designed to virtually eliminate. At December 31, 2007, we recognized proved bitumen reserves of 268 mmboe before royalties (234 after royalties) for our Long Lake Project, representing about 25% of our total proved oil and gas and Syncrude reserves before royalties.

Heavy Oil

Approximately 45% of our Canadian conventional production is heavy oil. Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Therefore, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also receives a lower price than light oil, as more expensive and complex refineries are required to refine heavy crude into higher-value petroleum products.

To maximize heavy oil returns, it is important to manage capital and operating costs. Our large production base and existing infrastructure are advantageous in managing these costs. In 2008, we plan to continue exploiting our existing fields through drilling and optimizing operations.

Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs, leaving substantial amounts of oil in the ground. This creates an opportunity to increase recovery factors by applying new technology. We are continuing to research various technologies to increase our heavy oil recoveries with several ongoing pilot projects in west-central Saskatchewan.

Natural Gas

Approximately 40% of our Canadian production is natural gas extracted primarily from shallow sweet reservoirs in southern Alberta and Saskatchewan and from sour gas reservoirs near Calgary. In general, shallower gas targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulfide. Our Balzac field, northeast of Calgary, has been producing sour natural gas since 1961. This sour gas is processed through our operated Balzac plant.

At the end of 2007, we held more than 725 net sections of land in Alberta with CBM potential.

Coalbed Methane (CBM)

Approximately 15% of our Canadian production is from our commercial CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area of central Alberta. We began commercial development in the Upper Mannville coals in 2005 by applying horizontal well technology to increase gas production rates and reduce de-watering time from water-saturated coal. Upper Mannville coals are generally deeper than the Horseshoe Canyon "dry coal" play, which is also being commercially developed in Alberta.

We have a long-term view of this business and plan to increase our CBM production by progressively developing opportunities on our extensive land base. At the end of 2007, we held more than 725 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. In 2007, we invested approximately $170 million in exploration and development activities. For 2008, we have slowed our pace of program spending until we gain clarity on the impact of Alberta royalty changes. In 2008, we plan to tie-in Upper Mannville development wells drilled in 2007 for production and commence development of our Horseshoe Canyon lands.

Shale Gas

As part of our growth strategy in unconventional Canadian resource plays, we acquired approximately 190 net sections of land in an emerging Devonian shale gas play in north eastern British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces, fractures or absorbed into organic matter. Currently, the United States is the largest producer of shale gas. In 2008, we plan to continue our evaluation program to demonstrate the feasibility of this resource.

Fiscal Terms

In Canada, we pay two types of royalties to federal and provincial governments on production from lands where they own the petroleum and natural gas rights. The first type is a gross royalty (Gross Royalty) system whereby we pay royalties ranging from 5% to 40% depending upon drilling date, production rate and product sales price. The second type of royalty (NPI) applies to our oil sands projects, which includes a 1% royalty on gross revenue prior to the recovery of capital costs. After achieving payout on these costs, the royalty converts to the greater of 1% of gross revenues or 25% of net profits.

During 2007, the Alberta government announced a new royalty framework effective January 1, 2009 that includes proposed increases to Alberta's royalty rates, although it has yet to be passed into legislation. Under the new framework, the upper limit of the Gross Royalty system is expected to increase to 50%, depending on production rate and product sales price. The new framework will also increase the royalty rates for the NPI royalty system that applies to oil sands projects. The new royalty rates for oil sands projects will range from 1% to 9% of gross revenue for projects that are pre-payout of capital costs, and from 25% to 40% of net profit for projects that are post-payout. These royalty rates will vary depending on WTI (US$55/bbl to US$120/bbl).

In addition to royalties, some provinces impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to crown royalties, ranging from 1.75% to 3.3%. In 2008, the rates will reduce slightly to 1.7% and 3.0%. In Alberta, we are subject to a freehold mineral tax of approximately 4%.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In late 2007, the federal government reduced the federal corporate income tax rate from 22% in 2007 to 15% by 2012. Provincial income tax rates vary from approximately 10% to 16%.

Middle East—Yemen

Yemen has been a significant international region since we first began production at Masila in 1993. We operate the country's largest oil project and have developed excellent relationships with the government and local communities.

Our strategy in Yemen is to maximize the value from our existing blocks, while we continue to search for new reservoirs in deeper horizons. We have two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2007, we produced 71,600 bbls/d of oil before royalties (39,800 after royalties), representing approximately 28% of Nexen's total production. Proved reserves of 41 mmboe before royalties (23 after royalties) comprise approximately 4% of Nexen's total proved oil and gas and Syncrude reserves before royalties (3% after royalties).

Masila Block (Block 14)

We operate the Masila Project with a 52% working interest. Our share of 2007 production was 57,000 bbls/d before royalties (29,900 after royalties). After more than 10 years of growth, our Masila fields have matured, but significant value still remains. As a result of the Production Sharing Agreement (PSA) terms that govern Masila production, we still expect to generate approximately 22% of total project free cash flow from the remaining proved reserves recoverable before the PSA expires in 2011.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993, with the first

lifting of oil in August 1993. Masila Blend oil averages 32° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations. Production is collected at our Central Processing Facility (CPF) where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal on the Indian Ocean and shipped to customers, primarily in Asia.

We are managing the pace of our drilling program to ensure we recover the remaining reserves in the most efficient, cost-effective manner. In 2008, we plan to drill ten development wells and sidetracks.

The Masila PSA was signed in 1987 between the Government of Yemen and the Masila joint venture partners (Masila Partners), including Nexen. Under the PSA, we have the right to produce oil from Masila into 2011 and to negotiate a five-year extension. Production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all exploration, development, and operating costs that are funded by the Masila Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

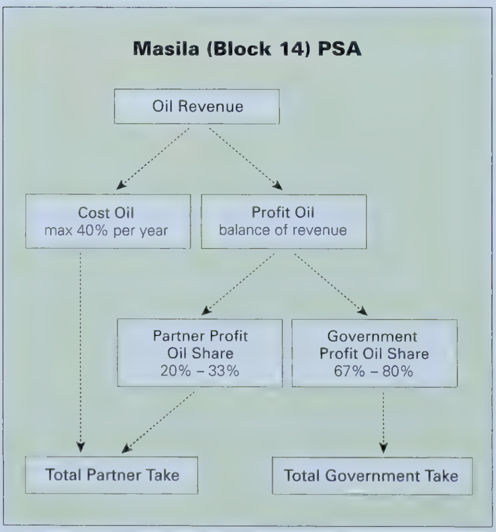
Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for 4 years
Development	16.7% per year for 6 years

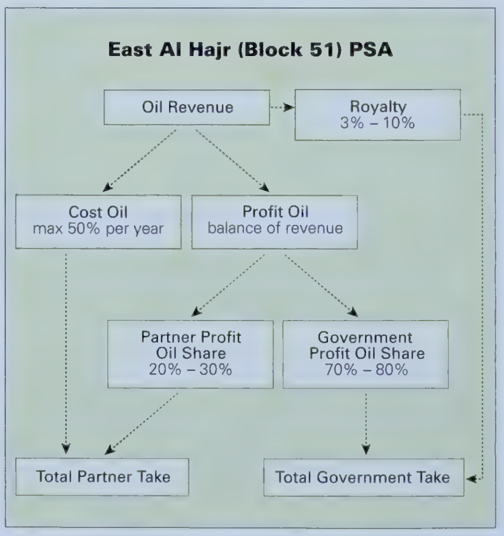
The remaining production is profit oil that is shared between the Masila Partners and the Government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20% to 33%. The structure of the agreement moderates the impact on the Masila Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the Government. The Government's share of profit oil includes a component for Yemen income taxes payable by the Masila Partners at a rate of 35%. In 2007, the Masila Partners' share of production, including recovery of past costs, was approximately 39%.

East Al Hajr Block (Block 51)

We operate Block 51, which is also governed by a PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners): The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures. Our effective interest is 100% and for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. We recognize both the Government's share and TYCO's share of profit oil under the PSA as royalties and taxes consistent with our treatment of our Masila operations. The PSA expires in 2023, and we have the right to negotiate a five-year extension. Under the PSA, the EAH Partners pay a royalty ranging from 3% to 10% to the Government depending on production volumes. The remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen. Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

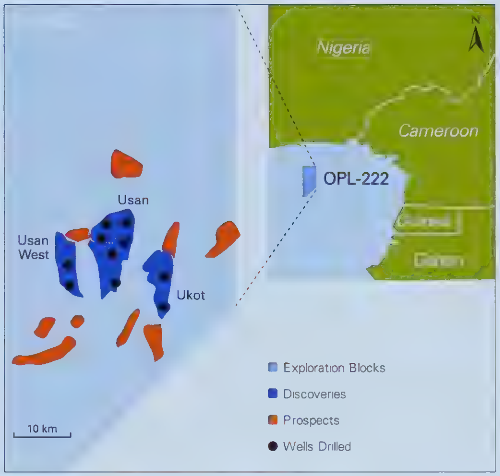
Costs	Recovery
Operating	100% in year incurred
Exploration	75% per year, declining balance
Development	75% per year, declining balance





The remaining production is profit oil that is shared between the EAH Partners and the Government on a sliding scale based on production rates. The EAH Partners' share of profit oil ranges from 20% to 30%. The Government's share of profit oil includes a component for Yemen income taxes payable by the EAH Partners at a rate of 35%. In 2007, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 54%.

The first successful exploratory well was drilled at BAK-A in 2003, with BAK-B discovered shortly after. Block 51 development began in 2004 and includes a CPF, gathering system and a 22-km tieback to our Masila export pipeline. Production began in November 2004. During 2007, production averaged 14,600 bbls/d before royalties (9,900 after royalties).



Offshore West Africa

Offshore West Africa is a core area where we already have discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to explore and develop our portfolio for medium- to long-term growth.

Nigeria

In 1998, we acquired a 20% non-operated interest in Block OPL-222 which covers 448,000 acres approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. Based on the drilling results outlined below, significant hydrocarbons exist on these blocks.

Year	Well	Location	Results
1998	Ukot-1	Ukot field discovery well	encountered three oil-bearing intervals and flowed at restricted rate of 13,900 bbls/d from two intervals
2002	Usan-1	Usan field discovery well	encountered several oil-bearing intervals and flowed at restricted rate of 5,000 bbls/d from one interval
2003	Usan-2	3 km west of discovery	appraised up-dip portion of the fault block
2003	Usan-3	2 km northwest of discovery	appraised separate fault block and flowed at restricted rate of 5,600 bbls/d from one interval
2003	Ukot-2	3.5 km south of discovery	encountered three oil-bearing intervals
2003	Usan-4	5 km south of discovery	flowed at restricted rate of 4,400 bbls/d from first interval and 6,300 bbls/d from second interval
2004	Usan-5	6 km west of discovery	sampled oil in several intervals
2004	Usan-6	4 km south of Usan-5	flowed at restricted rate of 5,800 bbls/d from one interval
2005	Usan-7	9 km southwest of discovery	confirmed an eastern extension of the field
2005	Usan-8	3 km southwest of discovery	confirmed an eastern extension of the field

Appraisal of the Usan field is complete and the field development continues to move forward. We expect the project to advance to the execution phase shortly and this will facilitate the award of the major deep-water facilities contracts. The project will have the ability to process an average of 180,000 bbls/d of oil during the initial production plateau period through a new FPSO with a two million barrel storage capacity. We have a 20% interest in exploration and development on this block. In 2008, we plan to invest approximately $165 million to progress development and award the major deep-water facilities contracts. At year-end 2007, proved reserves of 30 mmboe before royalties (25 after royalties) comprise approximately 3% of our total proved oil and gas and Syncrude reserves.

Other International

Colombia

Boqueron Block—Guando

In 2000, we made our first discovery at Guando on our 20% non-operated Boqueron Block. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Our working interest in Guando will decrease to 10% once the field has produced 60 million barrels of oil, which is expected to occur in early 2009. Our share of 2007 production averaged 6,200 bbls/d before royalties (5,700 after royalties), about 2% of Nexen's total production including Syncrude.

Production from Guando is subject to a royalty between 5% and 25% depending on daily production, and in 2007 averaged 8%. Colombian taxable income is subject to federal income tax of 34% in 2007 and 33% in 2008 and future years.

Exploration

We have interests in three exploration blocks in the Upper Magdalena Basin: El Queso acquired in 2003, Villarrica Norte Block in 2005 and El Guadual in 2007. In 2007, we drilled two unsuccessful wells; Guaini-1 and Atalea-1. We hold five technical evaluation agreements that each provide approximately one year to evaluate potential prospects. We are also identifying other growth opportunities in Colombia.

Norway

As part of our growth strategy in the North Sea, we participated in the 2006 bid round for exploration rights offshore Norway and were awarded interests in six licences covering nine blocks in early 2007. In 2008, we expect to invest approximately $40 million in additional seismic and geologic studies. In early 2008, we were awarded interests in three additional licences.

Norwegian oil and gas activities are subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax. A tax refund of 78% is received on tax losses arising from qualifying exploration expenses in Norway.

RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Net Sales by Product from Continuing Oil and Gas Operations (including Syncrude)

(Cdn$ millions)	2007	2006	2005
Conventional Crude Oil and Natural Gas Liquids (NGLs)	4,077	2,479	2,438
Synthetic Crude Oil	545	446	397
Natural Gas	499	553	671
Total	**5,121**	**3,478**	**3,506**

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 90% of our oil and gas net sales, while natural gas represents the remaining 10%.

Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price[1]			Average Production Cost[1]		
	2007	2006	2005	2007	2006	2005
Crude Oil and NGLs (Cdn$/bbl)						
Yemen	76.29	71.57	62.07	12.00	8.11	6.75
Canada[2]	44.07	42.79	40.51	18.67	15.50	14.01
United States	69.83	65.80	57.63	9.69	9.45	7.33
United Kingdom	76.30	71.19	60.55	6.94	11.28	14.90
Other Countries	71.29	66.09	59.96	3.76	3.13	6.08
Natural Gas (Cdn$/mcf)						
Canada[2]	6.32	6.49	7.51	2.28	1.65	0.95
United States	7.80	7.86	10.56	1.61	1.58	1.22
United Kingdom	4.71	7.43	7.86	1.16	1.88	2.48

Notes:

1 *Sales prices and unit production costs are calculated using our working interest production after royalties.*

2 *Includes results of discontinued operations for 2005 (See Note 14 to our Consolidated Financial Statements).*

Oil and Gas Acreage

	Developed		Undeveloped[1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Yemen[2]	50	29	756	628	806	657
Canada	797	610	1,871	980	2,668	1,590
United States	206	122	1,123	562	1,329	684
United Kingdom	202	83	1,290	846	1,492	929
Colombia[4]	1	–	607	372	608	372
Nigeria[2, 3]	–	–	448	90	448	90
Norway	–	–	280	134	280	134
Total	**1,256**	**844**	**6,375**	**3,612**	**7,631**	**4,456**[5]

Notes:

1 *Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.*

2 *The acreage is covered by production sharing contracts.*

3 *The acreage is covered by a joint venture agreement.*

4 *The acreage is covered by an association contract.*

5 *Approximately 20% of our net oil and gas acreage is scheduled to expire within three years if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licences.*

Producing Oil and Gas Wells

	Oil		Gas		Total	
(number of wells)	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Yemen	463	274	–	–	463	274
Canada	2,231	1,550	2,884	2,522	5,115	4,072
United States	193	94	202	141	395	235
United Kingdom	48	21	–	–	48	21
Colombia	121	25	–	–	121	25
Total	**3,056**	**1,964**	**3,086**	**2,663**	**6,142**	**4,627**

Notes:

1 *Gross wells are the total number of wells in which we own an interest.*

2 *Net wells are the sum of fractional interests owned in gross wells.*

Drilling Activity

2007

(number of net wells)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total
Yemen	1.0	1.0	2.0	28.0	–	28.0	30.0
Canada	23.2	0.6	23.8	295.6	3.2	298.8	322.6
United States	0.8	2.9	3.7	8.6	1.0	9.6	13.3
United Kingdom	2.0	3.2	5.2	4.2	–	4.2	9.4
Colombia	–	0.9	0.9	7.0	–	7.0	7.9
Total	**27.0**	**8.6**	**35.6**	**343.4**	**4.2**	**347.6**	**383.2**

2006

(number of net wells)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total
Yemen	3.0	5.5	8.5	36.0	1.0	37.0	45.5
Canada	35.4	2.2	37.6	214.3	0.7	215.0	252.6
United States	1.6	2.1	3.7	8.3	2.0	10.3	14.0
United Kingdom	0.8	1.7	2.5	5.5	–	5.5	8.0
Colombia	–	–	–	2.0	–	2.0	2.0
Nigeria	–	0.2	0.2	–	–	–	0.2
Total	**40.8**	**11.7**	**52.5**	**266.1**	**3.7**	**269.8**	**322.3**

2005

(number of net wells)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total
Yemen	0.5	4.6	5.1	33.0	1.6	34.6	39.7
Canada	32.2	8.0	40.2	198.9	0.5	199.4	239.6
United States	–	0.6	0.6	7.2	1.0	8.2	8.8
United Kingdom	0.5	2.1	2.6	1.5	–	1.5	4.1
Colombia	–	–	–	1.8	–	1.8	1.8
Nigeria	0.4	0.2	0.6	–	–	–	0.6
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
Total	**33.6**	**16.0**	**49.6**	**242.4**	**3.1**	**245.5**	**295.1**

Wells in Progress

At December 31, 2007, we were drilling 3 wells in Yemen (2 net), 2 wells in Canada (2 net), 4 wells in the United States (1.9 net), 3 wells in the United Kingdom (1.4 net), and 1 well in Colombia (0.2 net).

Proved Reserves including Proved Undeveloped Reserves

At December 31, 2007, we had 734 mmboe of proved oil and gas reserves before royalties (650 after royalties). This is a 1% increase over the prior year (2% after royalties). Including Syncrude, our total proved oil and gas and Syncrude reserves increased 1% to 1,058 mmboe (1% to 917 after royalties).

The following table provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding our Syncrude reserves during 2007. Refer to page 120 for proved reserves information on an after-royalties basis.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2006	364	182	73	66	40	725
Extension and Discoveries	7	10	4	2	–	23
Revisions	28	44	(12)	1	–	61
Acquisitions	–	1	11	–	–	12
Divestments	–	–	(2)	–	–	(2)
Production	(13)	(30)	(12)	(28)	(2)	(85)
December 31, 2007	**386**	**207**	**62**	**41**	**38**	**734**

Extensions and discoveries contributed 23 mmboe. The majority of the increase results from updip drilling at Buzzard in the North Sea, appraisal drilling at Longhorn in the Gulf of Mexico, and ongoing development of coalbed methane in Canada. Other increases relate to ongoing exploitation activities in the North Sea, Yemen, the Gulf of Mexico and Canada.

More than half of the 61 mmboe of positive revisions occurred at Buzzard where drilling results and production performance supported higher reserve estimates. About a third of the revisions are from our Long Lake Project where performance of analogous commercial SAGD projects support increased expected recoveries. The remaining positive revisions are primarily from price revisions in Canadian heavy oil properties and the Ettrick field, recovery factor improvements on our Canadian CBM lands and other areas. In the United States, the negative revision mainly relates to our deep-water Gulf of Mexico Aspen property where unsuccessful development drilling and production declines resulted in a reassessment of the property. In addition, four Gulf of Mexico shelf properties recognized negative reserve revisions from unsuccessful recompletions, production declines and increasing operating costs on older platforms reduced their economic life.

Acquisitions and divestments accounted for a net 10 mmboe addition (8 after royalties), primarily in the Gulf of Mexico where we acquired Shelf properties, pooled our deep-water Ringo well within the Longhorn development, and swapped our interest in Great White West for an overriding royalty interest in the entire Great White reservoir. In addition, we acquired additional interests in our operated Scott and Telford properties in the North Sea.

The following provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding Syncrude, during the past three years. Refer to page 120 for proved reserves information on an after royalty basis for the past three years.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2004	164	130	103	133	12	542
Extension and Discoveries	30	41	24	17	31	143
Revisions	283	79	(33)	(4)	1	326
Acquisitions	2	1	11	–	–	14
Divestments	(49)	–	(2)	–	–	(51)
Production	(44)	(44)	(41)	(105)	(6)	(240)
December 31, 2007	**386**	**207**	**62**	**41**	**38**	**734**

Since the end of 2004, we added 483 mmboe, sold 51 mmboe and produced 240 mmboe. Extensions and discoveries of 143 mmboe occurred primarily at our Usan, Ettrick and Buzzard fields, Canadian CBM and heavy oil, and the deep-water Gulf of Mexico. Our net positive revisions of 326 mmboe include economic revisions of 261 million boe, related to changes in year-end prices and costs. This includes 246 mmboe from reinstatement of Long Lake bitumen reserves that we had removed due to low bitumen prices at the end of 2004. The net technical revisions of 65 mmboe includes 77 mmboe of positive revisions in the UK primarily attributed to production performance at our Buzzard property and increased expected recoveries for our Long Lake Project. Negative technical revisions occurred primarily from lower-than-expected production performance at our Aspen field and some Shelf properties in the U.S. Gulf of Mexico. Our divestments are primarily from the 2005 sale of various Canadian properties.

Proved Undeveloped Reserves

The following table provides a summary of the proved undeveloped reserves (PUDs) for our oil and gas activities at the end of the last two years:

2007

	Before Royalties			After Royalties		
(mmboe)	PUDs	Total Proved [1]	% of Total	PUDs	Total Proved [1]	% of Total
Canada	236	386	61%	200	334	60%
United Kingdom	54	207	26%	54	207	26%
United States	20	62	32%	17	53	32%
Yemen	2	41	5%	1	23	4%
Other Countries	30	38	79%	25	33	76%
December 31, 2007	**342**	**734**	**47%**	**297**	**650**	**46%**

2006

	Before Royalties			After Royalties		
(mmboe)	PUDs	Total Proved [1]	% of Total	PUDs	Total Proved [1]	% of Total
Canada	216	364	59%	188	319	59%
United Kingdom	50	182	27%	50	182	27%
United States	9	73	12%	7	63	11%
Yemen	9	66	14%	5	38	13%
Other Countries	31	40	78%	25	35	71%
December 31, 2006	**315**	**725**	**43%**	**275**	**637**	**43%**

Note:
1 *Excludes proved reserves for our Syncrude operations of 324 mmboe (267 after royalties) in 2007 and 324 mmboe (274 after royalties) in 2006.*

In 2007, our PUDs increased by 27 mmboe (22 after royalties). We added 22 mmboe (14 after royalties) at Long Lake primarily relating to increased recovery factors on proved reserves outside of the initial 81 well-pair SAGD development area. We also added PUDs from ongoing activities at Buzzard, Ettrick, Longhorn and CBM. We converted 18 mmboe (14 after royalties) of PUDs to developed, with the majority relating to Buzzard, Masila, Block 51 and CBM development activities. Other small additions and conversions occurred from ongoing development activities in Canada, United States, United Kingdom and Colombia.

In Canada, our PUDs increased from 216 mmboe (188 after royalties) to 236 mmboe (200 after royalties). Substantially all of the increase relates to Long Lake. Long Lake PUDs of 228 mmboe (194 after royalties) are expected to be converted to developed over the next 20 years as we drill additional wells to provide feedstock to run the upgrader at capacity. The remaining PUDs relate to infill drilling, recompletions or facilities enhancements on our various heavy oil and natural gas fields. The majority of these PUDs are expected to be converted to producing reserves in 2008 and 2009. Also, a small portion of the PUDs relate to our CBM properties, which are expected to be converted to producing by infill drilling and field development planned for 2008 and 2009.

In the United Kingdom, our PUDs increased from 50 mmboe (50 after royalties) to 54 mmboe (54 after royalties). About 60% of the PUDs relate to Buzzard while the remainder relate to Ettrick. At Buzzard, we converted 6 mmboe of PUDs to producing and added 6 mmboe for increased recovery factors on remaining undrilled locations. The Buzzard PUDs are expected to be converted to proved over the next few years as we drill additional wells to keep the platform operating at capacity. We expect to convert the majority of Ettrick PUDs to producing when production is initiated in 2008.

In the United States, our PUDS increased from 9 mmboe (7 after royalties) to 20 mmboe (17 after royalties) largely as a result of the Green Canyon 6 acquisition, and activities at Longhorn and Great White, which are expected to be producing in the next two years. Almost all of the remaining PUDs are located in the deep water of the Gulf of Mexico.

In other countries, PUDs related primarily to our Usan development, offshore West Africa.

Excluding Long Lake and Usan, we expect to convert over 80% of our PUDs to producing in the next three years. Usan will be converted by 2012 when it is expected to come on stream. Long Lake PUDs will be converted over the next 20 years as new wells are drilled to offset declines from the initial SAGD wells. At the same time, we expect our ongoing exploration and development activities to continue to add new PUDs.

During the past three years, our total PUDs before royalties increased from 190 mmboe to 342 mmboe (165 to 297 after royalties). As a result, our PUDs before royalties as a percent of total proved reserves excluding Syncrude increased from 35% to 47% (37% to 46% after royalties). During this time, we converted 164 mmboe before royalties (148 after royalties) to developed. These conversions relate to completion of development of our Buzzard, Farragon and Duart fields in the United Kingdom and Block 51 in Yemen, and ongoing development of work elsewhere. We also added 316 mmboe before royalties (280 after royalties), primarily related to our active development projects at Long Lake, Usan, Ettrick and Longhorn.

Basis of Reserves Estimates

Reserve estimates in this report are internally prepared. Refer to the section on Critical Accounting Estimates—Oil and Gas Accounting—Reserves Determination on page 68 for a description of our reserves process. As described therein, we have at least 80% of our oil and gas reserve estimates either evaluated or audited annually by independent qualified reserves consultants. The nature and scope of the independent evaluations and audits is determined by agreement between us and the engineering firm. Independent assessments for other companies may, therefore, be different.

The following provides an overview of the nature and scope of the independent evaluations and audits that we have performed. An independent evaluation is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by assessing and interpreting all available data on a reservoir. An independent audit is a process whereby we request a third party engineering firm to prepare an estimate of our reserves by reviewing our estimates, supporting working papers and other data as they feel is necessary. The primary difference is that an auditor reviews our work and estimate in preparing their estimate whereas an evaluator uses the reservoir data to prepare their estimate.

In each case, we request their estimate be prepared using standard geological and engineering methods generally accepted by the petroleum industry. Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used is based on their professional judgement and experience. In preparing their estimates, they obtain information from us with respect to property interests, production from such properties, current costs of operations, expected future development and abandonment costs, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data. They may rely on the information without independent verification. However, if in the course of their evaluation they question the validity or sufficiency of any information, we request that they not rely on such information until they satisfactorily resolve their questions or independently verify such information. We do not place any limitations on the work to be performed. Upon completion of their work, the independent evaluator or auditor issues an opinion as to whether our estimate of the proved reserves for that portfolio of properties is, in aggregate, reasonable relative to the criteria set forth in SEC Rule 4-10(a)(2) of Regulation S-X. These rules define proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Our estimate may differ from the independent evaluators and auditors as they apply their professional judgement and experience, which may result in applying different estimating methods or interpreting data differently than us. We believe our estimate for a portfolio of properties is reasonable when it is, in aggregate, within 10% of the estimate of the independent evaluator or auditor.

We engaged DeGolyer and MacNaughton (D&M) to evaluate 100% of our reserves before royalties (100% after royalties) for the United Kingdom, Yemen Masila, Yemen Block 51 and Nigeria. A separate opinion was provided on each of these four areas. D&M provided an opinion on each of the areas that the proved reserves estimate prepared by us is, in aggregate, reasonable when compared to their estimate which was prepared in accordance with SEC Rules.

We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate 99% of our Canadian conventional, CBM and bitumen reserves before royalties (99% after

royalties) and to audit 100% of our Syncrude mining reserves before royalties (100% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. McDaniel provided an opinion that the proved reserves estimate prepared by us is, in aggregate, within 10% of their estimate which was prepared in accordance with SEC Rules.

We engaged Ryder Scott Company (Ryder Scott) to evaluate 79% of our US Gulf of Mexico shelf reserves before royalties (79% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. Ryder Scott provided an opinion that the difference between their estimate and ours is within the range of reasonable differences and that the estimates have been prepared in accordance with SEC Rules.

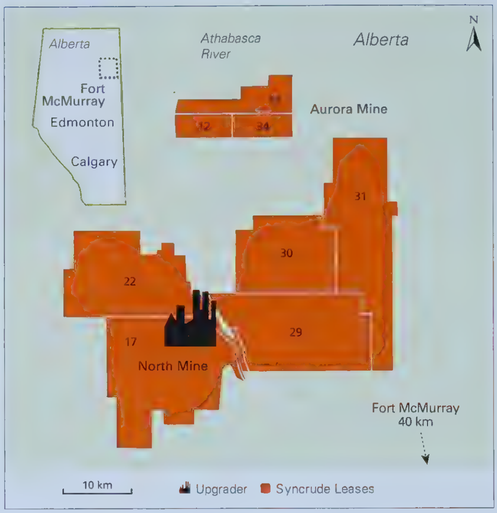
We engaged William M. Cobb & Associates, Inc. (Cobb) to evaluate 98% of our US Gulf of Mexico deep-water reserves before royalties (98% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. Cobb provided an opinion that the difference between their estimate and ours is within the range of reasonable differences and that the estimates have been prepared in accordance with SEC Rules.

SYNCRUDE MINING OPERATIONS

We hold a 7.23% participating interest in Syncrude Canada Ltd. (Syncrude). This joint venture was established in 1975 to mine shallow oil sands deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil.

Syncrude exploits a portion of the Athabasca oil sands that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14 percent by weight and ore bearing sand thickness of 100 to 160 feet. Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31, and 34) covering 248,300 hectares, 40 km north of Fort McMurray in northeast Alberta. Syncrude mines oil sands at three mines: Base, North, and Aurora North. These locations are readily accessible by public road. Trucks and shovels are used to collect the oil sands in the open pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 270 million tons of oil sands per year and from 150 to 160 mmbbls of bitumen per year depending on the average bitumen ore grade.



To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Base Mine uses hot water, steam and caustic soda to create a slurry, while at the North and Aurora North Mines, the oil sands are mixed with warm water to produce a slurry. Most of the water used in operations is recycled from the upgrader and mine sites. Incremental water is drawn from the Athabasca River in accordance with existing licenses. In late 2007, the Base Mine was shut down after Syncrude recovered all of the available oil sands in the final pit.

Our Syncrude production increased to 22,100 bbls/d in 2007, following completion of the Stage 3 expansion in 2006.

The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading. The resulting products are then separated into naphtha, light gas oil, and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2007, about 35% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 65% was sold to refineries in eastern Canada and the mid-western United States. Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than 1.8 billion barrels of synthetic crude oil to Edmonton, Alberta, by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.

At December 31, 2007, our total investment in the property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities, was approximately $1.3 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about $2.8 billion.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating license for the eight oil sands leases through to 2035. The license permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start up of operations in 1978.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 25 miles north of the main Syncrude site. The next expansion of Syncrude came on stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project.

Syncrude pays a royalty to the Alberta government. As of January 2002, this royalty was equal to the greater of 1% of gross revenue or 25% of net profit after deducting new capital expenditures. In connection with the government's review of Alberta royalty rates in 2007, the Syncrude owners entered into negotiations at the end of 2007 at the request of the government that may result in revised royalty terms. These negotiations may result in higher royalties paid to the Alberta government in the future.

In 2007, Syncrude's production of marketable synthetic crude oil was 305,000 bbls/d. Nexen's share was 22,100 bbls/d before royalties (18,800 after royalties).

The following table provides some operating statistics for Syncrude operations:

	2007	2006	2005
Total Mined Volume [1]			
Millions of Tons	470	428	353
Mined Volume to Oil Sands Ratio [1]	2.1	2.2	2.1
Oil Sands Processed			
Millions of Tons	220	192	169
Average Bitumen Grade (weight %)	11.6	11.3	11.1
Bitumen in Mined Oil Sands			
Millions of Tons	26	22	19
Average Extraction Recovery (%)	92	90	89
Bitumen Production [2]			
Millions of Barrels	133	112	94
Average Upgrading Yield (%)	84	85	85
Gross Synthetic Crude Oil Shipped [3]			
Millions of Barrels	111.3	94.3	78.1
Nexen's Share of Marketable Crude Oil			
Millions of Barrels Before Royalties	8.1	6.8	5.7
Millions of Barrels After Royalties	6.9	6.2	5.6

Notes:

1 *Includes pre-stripping of mine areas.*

2 *Bitumen production in barrels is equal to bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.*

3 *Approximately 1.0% of the produced synthetic crude oil is used internally, primarily for diesel that fuels the trucks and shovels at Syncrude. The remaining synthetic crude oil is sold externally.*

ENERGY MARKETING

Our marketing group sells proprietary and third-party natural gas, crude oil, natural gas liquids, ethanol and power in certain regional global markets. We have built a solid strategic presence within various North American regional markets and have extended our presence into certain global markets. We focus on securing access to transportation, storage and facilities, as well as the commodities we produce or acquire. We optimize the margin on our base business by physically and financially trading around our access to these physical assets. We also trade financially for profit where we see opportunities in the market. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our oil and gas production;
- provide market intelligence in support of our oil and gas operations;
- provide superior customer service to producers and consumers;
- capitalize on market opportunities through physical and financial trading; and
- optimize physical assets or contracts to which we have access.

This strategy aligns with our corporate focus on realizing the full value from our assets and provides us with the market intelligence needed to deliver current and future oil and gas production to market at competitive pricing.

North American Gas Marketing

The marketing and trading of North American natural gas is our marketing group's largest revenue source. We focus on key regional markets where we have a strategic presence—solid customer relationships, in-depth understanding of the market or established physical assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further revenue by:

- capitalizing on location spreads (differences in prices between locations) using our transportation assets;
- capitalizing on time spreads (differences in prices between summer and winter) using our storage assets; and
- financial trading of location and time spreads.

We have offices in key regions including Calgary, Detroit and Houston. Our Calgary office provides a variety of services, including supply, storage, and transportation management as well as netback pool arrangements and other customer services. Our customers include producers and consumers in western Canada as well as consumers (including utilities) in eastern Canada, the north-eastern United States and the US mid-continent. Our Detroit office works closely with Calgary to provide services to our customers and our presence in Houston has established us in the Gulf Coast region. We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

Marketing Office Locations

In 2003 and 2004, we grew our asset base by acquiring physical gas purchase and sales contracts, as well as natural gas transportation capacity, on favourable terms. This gave us access to new third party gas supply until the end of 2008, pipeline capacity to 2016 and new relationships that have enabled us to negotiate new gas purchase and sales contracts. We continue to pursue opportunities to grow our storage and transportation positions by reviewing acquisitions and participating in the normal bidding processes. Our position as a physical marketer at multiple delivery points in key markets gives us flexibility to capitalize on time and location spreads. With pipeline capacity, we can move gas from producing regions to take advantage of price differences. At the end of 2007, we held 2 bcf/d of pipeline capacity, primarily between western Canada and the eastern US, and we continue to expand our presence into other markets within North America. We also use storage capacity to store normally cheaper summer gas in the ground until the winter heating season arrives. We had access to 39 bcf of natural gas storage facilities at the end of the year.

At year end, we had access to 39 bcf of natural gas storage facilities.

In addition to transportation and storage assets, we enter into financial contracts that enable us to capture profits around time and location spreads. The risks we assume on these contracts are based on fundamental analysis and knowledge of regional markets. The risk is managed pro-actively by our product group teams and monitored by our risk group, with regular reporting to management and the board of directors.

North American Crude Oil Marketing

Our crude oil business focuses on marketing physical crude oil to end-use refiners. The crude oil group markets Nexen's production and more than 650,000 bbls/d of third-party production. In addition to physical marketing, we take advantage of quality, time and location spreads.

Our North American operations focus on key regions supported by our offices in Calgary, Houston and Denver. In western Canada, our producer services group concentrates on purchasing from a diversified supply base, while our trading team seeks to optimize the mix for sale to refiners. Traditionally, the Chicago and Denver areas have been key markets for our western Canadian crude, however, we continue to expand our presence into the US Gulf Coast. Our deep-water Gulf of Mexico crude oil production has expanded our presence in that market through our Houston office. At the end of 2007, we had access to 2.7 mmbbls of storage and over the course of the year, marketed approximately 655 mbbls per day.

Our operations also include North American natural gas liquid (NGL) and ethanol businesses that focus on buying and selling NGLs, as well as ethanol and natural gasoline. These businesses acquire and move product within North America. They also provide natural gasoline as a denaturant for ethanol production and market the finished ethanol in the US. At the end of 2007, we had access to 550 mbbls of NGL storage and over the course of the year, moved approximately 26 mbbls per day of product.

Our crude oil marketing group also enters into financial contracts intended to capture trading profits around time, quality and location spreads. Like gas marketing, the risks assumed are based on fundamental analysis and proprietary knowledge of regional markets, and are monitored by our risk group.

North American Power Marketing

Our power marketing group is responsible for optimizing our 50% interest in a 120 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, as well as our 50% interest in the 70 MW Soderglen wind power operation in southern Alberta. We also market power to larger commercial, industrial and municipal clients in Alberta. We are currently the largest supplier of power to commercial and industrial sectors in the province. Our Balzac facility began operations in 2001 and Soderglen in October 2006. We expect to increase our power generation capacity with a 170 MW cogeneration facility at Long Lake in 2008. We have a 50% interest in this project.

Europe

In 2006, we acquired Foundation Energy, a UK-based European gas and power marketing business. Our trading strategies include capitalizing on time and location spreads involving the UK and German gas and power markets, using primarily financial contracts. We are increasing our presence in both the UK and continental Europe physical gas markets. During the year, we secured access to transportation and storage capacity in the UK and Europe. We recruited an experienced crude oil marketing team and established an office in London, UK in 2006 to maximize the value of our North Sea production. The team began successfully marketing Buzzard crude oil production in 2007.

Asia

Our international team in Asia continues to focus on the physical marketing of Masila crude oil. In order to meet customer needs, we may occasionally market other regional crude types. In addition to our own crude, we market production for our partners and third parties in the Yemen region. By locating our international crude oil marketing office in Singapore, we are well positioned to serve both the producing region and the Asian refining market.

CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. We have retained a 61.4% interest in our chemicals business, and we continue to fully consolidate chemicals in our Consolidated Financial Statements.

Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing facilities are modern, reliable and strategically located to capitalize on competitive power costs or transportation infrastructure to minimize production and delivery costs. This enables us to have reliable supplies and low costs—key factors for marketing bleaching chemicals.

Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products, making up over half our cash costs. Therefore, our current facilities are strategically located to take advantage of economic power sources. Our second highest cost is transportation. The proximity of our manufacturing plants to major customers and competitive freight rates minimize our transportation costs. Labour is also a significant manufacturing cost. Approximately 50% of our workforce is unionized with collective agreements in place at all of our unionized plants.

To grow value in our chemicals business, we focus on reducing our costs while maintaining market share, building a sustainable North American customer base and capturing new offshore opportunities.

North America

The North American pulp and paper industry consumes approximately 95% of the continent's sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume adjustment provisions. Approximately 32% of this production is sold in Canada, 61% in the US, and the rest is marketed offshore.

We are the third-largest manufacturer of sodium chlorate in North America with four Canadian facilities: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; and Beauharnois, Quebec.

In October 2004, we completed an expansion of our Brandon plant, increasing capacity to 260,000 tonnes per year. Brandon is the world's largest sodium chlorate facility and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America. In late 2006, we began another expansion at Brandon which is expected to increase capacity by 33,000 tonnes per year, by mid 2008.

Our chlor-alkali facility at North Vancouver, British Columbia, manufactures caustic soda, chlorine and muriatic acid. Almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States. In early 2008, a technology conversion project for the North Vancouver facility was sanctioned. The conversion project will replace existing diaphragm technology and assets with newer, proven membrane technology that is expected to be more cost effective and will expand productive capacity by 35%. The project is expected to be completed early 2010.

Average Annual Production Capacity

(short tons)	2007	2006	2005
Sodium Chlorate			
North America	450,055	446,208	446,208
Brazil	68,563	68,563	68,563
Total	**518,618**	**514,771**	**514,771**
Chlor-alkali			
North America	364,500	356,002	356,002
Brazil	109,430	109,430	109,430
Total	**473,930**	**465,432**	**465,432**

Brazil

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Cellulose S.A. (Aracruz), the leading manufacturer of pulp in Brazil. The majority of the sodium chlorate production is sold to Aracruz under a long-term sales agreement that expires in 2024. Most of the chlorine and about 15% of the sodium chlorate production is sold in the merchant market under shorter-term contracts. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. The majority of our electricity needs are supplied by a long-term supply contract in Brazil.

GOVERNMENT REGULATIONS

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We participate in many industry and professional associations and monitor the progress of proposed legislation and regulatory amendments.

ENVIRONMENTAL REGULATIONS

Our oil and gas, Syncrude and chemical operations are subject to government laws and regulations designed to protect and regulate the discharge of materials into the environment in countries where we operate. We believe our operations comply in all material respects with applicable environmental laws. To reduce our exposure, we apply industry standards, codes and best practices to meet or exceed these laws and regulations. Occasionally, we may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

We have an active safety, environment and social responsibility group that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner. We have developed policies for continuing compliance with environmental laws and regulations in the countries in which we operate.

Environmental Provisions and Expenditures

The ultimate financial impact of environmental laws and regulations is not clearly known and cannot be reasonably estimated as new standards continue to evolve in the countries in which we operate. We estimate our future environmental costs based on past experience and current regulations. At December 31, 2007, $832 million ($2,165 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations. In 2007, we increased our retirement obligations for future dismantlement and site restoration by $105 million primarily from ongoing development of the Long Lake Project in the Athabasca oil sands and from industry cost pressures in the North Sea.

In 2007, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $23 million. Our operating expenditures for environmental-related matters were approximately $4 million. In 2008, we estimate these expenditures to be approximately $27 million.

EMPLOYEES

We had 4,058 employees on December 31, 2007, of which 326 were employed under collective bargaining schemes. Information on our executive officers is presented in Item 10 of this report.

ITEM 1A. RISK FACTORS

RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in our industry and some of which are unique to our operations.

A substantial or extended decline in oil and natural gas prices could have a material adverse effect on us.

Crude oil and natural gas are commodities which are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for oil and gas exploration and development.

Our crude oil prices are based on various reference prices, primarily Brent and West Texas Intermediate (WTI) crude oil reference prices and other prices which generally track the movement of Brent and WTI. Adjustments are made to the reference price to reflect quality differentials and transportation. Brent, WTI and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

Competitive forces may limit our access to natural resources, and create labour and equipment shortages.
The oil and gas industry is highly competitive, particularly in the following areas:

- gaining access to areas or countries known to have available resources;
- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include national oil companies, major integrated oil and gas companies and various other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. The pulp and paper chemicals market is also highly competitive. Key success factors in each of these markets are price, product quality, and logistics and reliability of supply.

Competitive forces may result in shortages of prospects to drill, shortages of labour and equipment to carry out exploration, development or operating activities, and shortages of infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could negatively impact our costs and prices and, therefore, our financial results.

Exploration, development and production risks and natural disasters could result in liability exposure or loss of production or reserves.
Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

We operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. At Balzac, just north of Calgary, we operate a gas plant that has been producing sour gas for over 45 years. Through our ownership in Canexus Limited Partnership, we operate a chlor-alkali plant in North Vancouver that has been producing chlorine for almost 50 years.

We may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may materially impact our financial results.

Our offshore operations are subject to unique operating risks.
Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production.

Our operations in the Gulf of Mexico have been suspended, from time to time, due to hurricanes or tropical storms. In the last five years, we have had a few instances where production was suspended for an extended period of time and damage to facilities was incurred. In late August 2005, we shut-in all of our production in the Gulf of Mexico, consisting of approximately 50,000 boe/d before royalties, and ceased drilling operations in anticipation of Hurricane Katrina. Production was restored in early September for most of our fields. In late September 2005, we again shut-in all of our production and ceased drilling operations in anticipation of Hurricane Rita. While we incurred minimal damage to most of our facilities, extensive damage was incurred to the third party infrastructure necessary to accommodate our production. As a result, our 2005 annualized production was reduced by approximately 6,000 boe/d. These storms also resulted in damage to rigs under contract with us, which increased our costs and delayed our drilling schedule. In each of these instances, there was no significant financial impact after business interruption and property insurance claims.

Our exploration and development capital programs in our offshore operations are exposed to risk of delay or additional costs by limited access to drilling rigs. Recent industry pressure in the Gulf of Mexico has reduced the availability of drilling rigs. Our profitability and success at finding reserves or bringing new production on stream may be reduced by extended delays and/or higher costs of obtaining drilling rigs.

Without reserve additions, our reserves and production will decline over time and we require capital to produce remaining reserves.
Our future crude oil and natural gas reserves and production, and therefore our operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration,

development or acquisitions, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves and production will be impaired.

Discovered oil and natural gas reserves are generally only produced when they are economically recoverable. As such, oil and gas prices and capital and operating costs have an impact on whether reserves will ultimately be produced. As required by SEC rules, our proved reserves represent the quantities that we expect to economically recover using prices and costs at the end of the year. Accordingly, proved reserves can increase or decrease under different price and cost scenarios. Our bitumen reserves are particularly sensitive to year end prices and costs. Under SEC rules, we are required to recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce from the Long Lake Project. As a result, we expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen reserves are sensitive to year-end prices. In particular, since we recognize our oil sands as bitumen reserves and they are related to one project, all or none of the reserves will likely be considered economic depending on the year-end prices for bitumen, diluent and natural gas, even though the Long Lake Project has minimal exposure to these factors.

Our proved reserves include undeveloped properties that require additional capital to bring them on-stream.
Under SEC rules, the definition of proved undeveloped reserves includes reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells may begin production. Such reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates. At December 31, 2007, 47% of our proved reserves before royalties (46% after royalties) were undeveloped. Refer to page 20 for information on PUDs.

Our heavy oil production is more expensive and yields lower prices than light oil and gas.
Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil making it more susceptible to supply and demand fundamentals which may cause the price to decline.

Any one or a combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

The Long Lake Project faces additional risks compared to conventional oil and gas production.
The Long Lake Project is planned as a fully integrated production, upgrading and cogeneration facility. We intend to use steam assisted gravity drainage (SAGD) technology to recover bitumen from oil sands. As designed, the bitumen will be partially upgraded using the proprietary OrCrude™ process, followed by conventional hydrocracking to produce a sweet, premium synthetic crude oil. The OrCrude™ process also yields liquid asphaltines that will be gasified into syngas. This syngas will be used as fuel for the SAGD process, a source of hydrogen in the upgrading process, and to generate electricity through a cogeneration facility.

We have a 50% working interest in this project, and our share of the capital costs is estimated to be between \$2.9 billion and \$3.05 billion (\$5.8 billion and \$6.1 billion gross). This includes a contingency reserve of \$150 million (\$300 million gross) for cost and productivity pressures over and above current trends. Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

In addition to the risks associated with heavy oil production stated above, risks associated with our Long Lake Project include the following:

Uncertain Time Line and Cost of the Project

The Long Lake Project is currently in the construction and commissioning stage. There is a risk that actual costs to construct and develop may be higher than expected or that the project may not be completed on time or at all due to many factors, including:

- construction performance falling below expected levels of output or efficiency;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- inability to attract sufficient numbers of qualified workers;
- design errors;
- contractor or operator errors;
- non-performance by third-party contractors;
- changes in project scope;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- breakdown or failure of equipment or processes;
- violation of permit requirements;
- catastrophic events such as fires, earthquakes, storms or explosions; and
- disruption in the supply of energy.

The capital cost estimate at the time our board sanctioned the project in February 2004 was $3.4 billion (gross). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to increase certainty and reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million (gross). In early 2006, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million (gross). These scope changes increased the estimated project cost to $3.8 billion. High activity in the oil sands region is placing ongoing pressure on the costs of labour and services. In addition, labour productivity has been lower than anticipated, requiring a larger workforce to maintain progress. In October 2007, we announced that the projected cost estimate for Phase 1 ranges from $5.8 to $6.1 billion ($2.9 to $3.05 billion net to Nexen). We are on track to complete the construction and commence commissioning of all units in sufficient time for first production of synthetic crude oil in mid 2008.

Application of Relatively New SAGD Bitumen Recovery Process

SAGD has been used in western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade. However, application of SAGD to the in-situ recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, however several commercial SAGD projects have been in steady state operation for over five years.

Our estimates for performance and recoverable volumes for the Long Lake Project are based primarily on our three well-pair SAGD pilot and industry performance from SAGD operations in like reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our assumptions included average well-pair productivity of 900 bbls/d of bitumen and a long-term steam-to-oil ratio of 3.0. There can be no certainty that our SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, purchase natural gas for additional steam generation, and/or make short-term bitumen purchases. These could have a significant adverse impact on the future activities and economic return of the Long Lake Project.

Application of New Bitumen Upgrading Process

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude will be the first commercial application of the process although we have operated it in a 500 bbl/d demonstration plant. There can be no certainty that the commercial upgrader being constructed at Long Lake will achieve the same or similar results as the demonstration plant or the results which are forecast. If we are unable to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading it, which would expose us to the following risks:

- the market for bitumen is limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent which may cause its price to increase;
- the market price for bitumen is relatively low reflecting its quality differential;
- the market price for bitumen fluctuates over the course of the year; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake Project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from those we have assumed. This would materially decrease expected earnings from the project and the project may not be profitable under these conditions.

Dependence on OPTI Canada Inc.

We are undertaking the Long Lake Project jointly with OPTI Canada Inc. (OPTI) pursuant to a joint venture agreement governing the construction, ownership and joint operation of the project. The agreement provides for a management committee that is responsible for the supervision and direction of the management and operation of the project, the supervision and control of the operators and all other matters relating to the development of the project. If our interest in any element of the project falls below 25%, OPTI may be able to make decisions respecting that element without our input, which may adversely affect our operations.

Dependence upon Proprietary Technology

The success of the project and our investment depends highly on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licensed by OPTI. OPTI currently relies on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licenses and patents, to secure the rights to utilize its proprietary technology and the proprietary technology of third parties. OPTI may have to engage in litigation to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of patents or proprietary rights of third parties. This kind of litigation can be time-consuming and expensive, whether OPTI is successful or not. The process of seeking patent protection can itself be long and expensive, and there can be no assurance that any currently pending or future patent applications of OPTI or such third parties will actually result in issued patents, or that, if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Furthermore, others may develop technologies that are similar or superior to: 1) the technology of OPTI or third parties or 2) the design around the patents owned by OPTI and/or third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for additional technologies required to possibly further expand the Long Lake upgrader.

Operational Hazards

The operation of the project will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions, and our insurance may not sufficiently cover casualty occurrences or disruptions that occur. The project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. The project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher-value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit depend largely on production levels.

The Long Lake Project will process large volumes of hydrocarbons at high pressure and temperatures and will handle large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake Project will produce sour gas, which is gas containing hydrogen sulphide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. The project will include integrated facilities for handling and treating the sour gas, including the use of gas sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shut down of operations.

The Long Lake Project will produce carbon dioxide emissions. Risk factors relating to environmental regulation are provided separately in this document.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the project and most

of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Long Lake Project and on us.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including exploring for, and developing, new sources of supply, acquiring petroleum interests and distributing and marketing of petroleum products. The Long Lake Project competes with other producers of synthetic crude oil blends and other producers of conventional crude oil. Some conventional producers have lower operating costs than the project is anticipated to have. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies, other than OPTI and us, have announced plans to: 1) enter the oil sands business and begin producing synthetic crude oil, or 2) expand existing operations. Either plan could materially increase the supply of synthetic crude oil and other competing crude oil products in the marketplace. Depending on future demand, increased supplies could have a negative impact on prices.

Some of our production is concentrated in a few producing assets.

A significant portion of our production is generated from highly productive individual wells or central production facilities. Examples include:

- Scott and Buzzard production platforms in the North Sea;
- central processing facilities, oil pipelines, and export terminal at our two Yemen operations;
- Gunnison SPAR production platform in the Gulf of Mexico;
- Aspen wells tied-in to a third-party processing facility in the Gulf of Mexico; and
- upgrading facilities at Syncrude in the Athabasca oil sands.

As significant production is generated from each asset, any single event that interrupts one of these operations could result in the loss of production.

Our operations could be subject to changes in regulations related to air emissions.

The Kyoto Protocol came into force on February 16, 2005 and Canada ratified the Kyoto Protocol in December 2002. In 1997, Canada committed to an emission reduction of 6% below 1990 levels during the First Commitment period (2008 to 2012). Alberta became the first jurisdiction in Canada to enact and implement binding emission reductions (a 12% reduction in carbon intensity) on facilities emitting more than 100 kilo-tonnes of CO_2 equivalent. Facilities unable to make internal reductions have unlimited access to a technology fund at the rate of $15 per tonne of CO_2 equivalent. In 2007, the Federal government introduced a Regulatory Framework for Air Emissions which indicates that the government intends to regulate both greenhouse gases and air pollutants beginning as early as 2010, with progressively more stringent reductions applied out to 2050. Greenhouse gases (GHGs) will be regulated based on intensity until 2020 – 2025, when a cap and trade system may be imposed. The intent appears to offer companies the option of making internal reductions, purchasing offsets or making payments into a technology fund (with escalating fixed costs). During the period 2010 to 2020 there will be increasing exposure to a Canadian carbon market which could be short of supply leading to very high carbon prices. It remains to be seen if the two levels of government will harmonize their compliance regimes and how the revenue in the technology funds will be allocated. The federal government has also indicated their intent to regulate air pollutants concurrent with greenhouse gases but their schedule and long-term objectives are less clear. Based on what is known today, there could be technical challenges in meeting some of the criteria for certain pollutants.

Any required reductions in the GHGs emitted from our operations could result in increases in our capital or operating expense, or reduced operating rates, especially at the Long Lake Project, which could have an adverse effect on our results of operations and financial condition. As a "new facility" starting operations in 2008, Long Lake will have three years to establish an emissions baseline before having a reduction obligation assigned. In 2007 our Canadian operations, including Syncrude, accounted for 23% of our production before royalties.

Our two installations in the UK sector of the North Sea have allocations from the regulator and are part of the European Union Emission Trading System. The allocations cover emissions from combustion equipment and flaring from 2008 until 2012. The installations are both expected to have emissions in excess of allowances which will be covered by eligible offsets from the Clean Development Mechanism and over-the-counter trades.

Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our trading operations expose us to the risk of financial losses from various sources. The markets in which we trade are susceptible to significant changes, which could expose us to the risk of material financial losses. Significant changes in the commodities and financial markets could require us to provide additional liquidity to support our energy marketing operations.

Adverse credit related events such as a downgrade of our credit rating to non-investment grade could require additional collateral to be placed with counterparties. Any significant loss of liquidity could adversely affect our financial condition.

Use of marine transportation may expose us to the risk of financial loss and damaged reputation.
From time to time, we may choose to charter marine vessels for the transportation of crude oil. This may expose us to the risk of financial loss and damaged reputation in the event of oil spills.

Fluctuations in exchange rates give rise to foreign currency exposure.
Many of our activities are transacted in or referenced to US dollars. Revenues, expenses, capital expenditures and related net assets of our oil and gas and chemicals operations outside Canada are primarily US-dollar denominated. Prices received in Canada for sales of our crude oil, natural gas and some chemicals products are referenced to US-dollar denominated prices. Also, we have the ability to borrow on a short-term and long-term basis in US dollars. Fluctuations in exchange rates between the US and the Canadian dollar, and between US or Canadian dollar and other foreign currencies, including but not limited to the British pound and the Euro, could adversely affect our financial condition.

Increases in interest rates could give rise to increased debt servicing obligations.
We use both fixed and floating rate debt to finance our operations. Our floating rate debt obligations expose us to changes in interest payments due to fluctuating interest rates. This could adversely affect our financial condition.

The inability of counterparties to fulfill their obligations to us could adversely impact our results of operations.
Credit risk affects both our trading and non-trading activities and there is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our receivables are with counterparties in the energy industry and are subject to normal industry credit risk. The inability of any one or more of these counterparties to fulfill their obligations to us may adversely impact our results of operations.

We may not achieve commercial production rates in our coalbed methane or shale gas operations.
Part of Nexen's growth strategy is unconventional Canadian gas resource plays, including coalbed methane (CBM) and shale gas. Both gas resource plays have significant potential; however, exploitation techniques and practices for these resources in Canada generally remain in the early stages of development and it is very difficult to determine whether or not these resource plays will prove commercial, or to what degree.

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal. Some of the uncertainties associated with development of CBM resources are as follows:

- If the coalbed is water saturated, such as the Mannville coals in the Fort Assiniboine region of Alberta, water generally needs to be extracted to reduce the pressure and allow gas production to occur. A significant period of time may be required to dewater these wet coals and determine if commercial production is feasible. We may also have to invest significant capital in these assets before they achieve commercial rates of production, if ever;
- Some coalbeds may not have sufficient natural permeability in the coalbed to recover the gas in place and can therefore require more extensive, and expensive, completion technologies which can increase the cost of drilling and production;
- The public may react negatively to certain water disposal practices related to water saturated CBM projects, even though these water disposal practices are regulated to ensure public safety and water conservation. Nevertheless, negative public perception around water saturated CBM production could impede our access to the resource;
- CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area; and
- Regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

Shale gas is an unconventional gas produced from reservoirs composed of organic rich shales. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Some of the uncertainties associated with development of shale gas resources are as follows:

- Shale gas wells typically have higher production decline rates, lower producing rates and reserves per well than conventional gas wells, although this varies by area;
- Regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain; and
- Shales are typically less permeable than conventional gas reservoirs, and can therefore require more extensive, and expensive, completion technologies which can increase the cost of drilling and production.

We have significant up-front commitments related to our current development projects.
We have significant commitments in connection with various development activities currently underway. At Long Lake, we essentially completed module and site construction of the SAGD facilities in 2006 and steam injection began in 2007. Module fabrication of the Long Lake Upgrader is complete and all modules are on site. Construction of the upgrader is approximately 97% complete and start up is scheduled for mid 2008. At Long Lake, we are exposed to the possibility of cost overruns and/or delays in the commencement of commercial production, which may be significant. Specific risk factors relating to our Long Lake oil sands project are provided separately. See "The Long Lake Project faces additional risks compared to conventional oil and gas production".

We operate in countries with political and economic risk.
We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists which may have material adverse financial consequences. For instance, on September 15, 2006 our oil export terminal in Yemen was assaulted by two explosive laden vehicles. One worker was killed and two others received minor injuries. The ability of the terminal to receive and export oil was not affected and operations continued as normal. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

We may be affected by changes in government rules and regulations.
Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. For example, the US government has proposed increases to the royalty rates for new deep-water Gulf of Mexico leases and has proposed amendments to deep-water leases issued in 1998 and 1999. In 2007, the Alberta government proposed changes to royalty rates effective 2009. Current legislation is generally a matter of public record, and we cannot predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. Changes in government regulations could adversely affect our results of operations and financial condition.

Our operations are exposed to environmental liabilities.
Environmental liabilities inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by disposing or releasing specified substances. This could have an adverse financial consequence on us.

Certain operations require the use of fresh and saline water. We currently use sub-surface sources of water for these operations. Additional costs may be incurred if allocation limits are placed on our saline water usage, if our sub-surface fresh water needs exceed allocated amounts or if existing sub-surface fresh water allocations are reduced.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments with the SEC.

Item 3. Legal Proceedings

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect on our consolidated financial position or results of operations. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US Environmental Protection Agency (EPA), state environmental agencies, and certain third parties for certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands, and lawsuits have been received for certain sites related to historical operations and activities in the US for which, although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2007.

PART II
Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY.

On December 31, 2007, there were 1,569 registered holders of common shares and 528,304,813 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings. During the year, we made no purchases of our own equity securities.

Trading Range of Nexen's Common Shares

	TSX (Cdn$)		**NYSE** (US$)	
($/share)	High	Low	High	Low
2007				
First Quarter	37.60	29.66	31.88	25.18
Second Quarter	36.51	31.25	32.21	29.08
Third Quarter	36.32	27.21	34.79	25.25
Fourth Quarter	32.63	27.88	34.37	27.58
2006				
First Quarter	34.05	27.17	29.97	23.49
Second Quarter	34.75	25.41	30.84	22.82
Third Quarter	35.61	26.07	31.82	23.35
Fourth Quarter	32.90	26.46	29.19	23.45

Quarterly Dividends Declared on Common Shares

($/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2007	0.025	0.025	0.025	0.025
2006	0.025	0.025	0.025	0.025

Payment date for dividends was the first day of the next quarter. All dividends paid to holders of common shares in 2007 have been designated as "eligible dividends" for Canadian tax purposes.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian", as defined, file notice with Investment Canada and obtain government approval prior to acquiring control of a Canadian business, as defined. Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities (refer to the table of securities authorized for issuance under equity compensation plans on page 154).

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. According to the Plan, a right is attached to each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares, and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our board can defer the separation date.

Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2008 to remain effective past that date. A copy of the Plan is available on our web site at www.nexeninc.com.

Item 6. Selected Financial Data

Five-Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn$ millions, except otherwise indicated)	2007	2006	2005	2004	2003
Oil & Gas and Syncrude Production					
Production Before Royalties (mboe/d) [1]	254	212	242	250	269
Production After Royalties (mboe/d) [1]	207	156	173	174	185
Results of Operations					
Revenue					
Oil & Gas and Syncrude [2]	5,174	3,656	3,535	2,573	2,261
Marketing	926	1,373	864	625	586
Chemicals	447	413	413	383	377
Other	(26)	(47)	(193)	59	31
Total Revenue	6,521	5,395	4,619	3,640	3,255
Net Income from Continuing Operations	1,012	579	658	705	419
Basic Earnings per Common Share from Continuing Operations ($/share) [3]	1.92	1.10	1.26	1.37	0.85
Diluted Earnings per Common Share from Continuing Operations ($/share) [3]	1.88	1.08	1.23	1.35	0.84
Net Income	1,012	579	1,110	788	420
Basic Earnings per Common Share ($/share) [3]	1.92	1.10	2.13	1.53	0.85
Diluted Earnings per Common Share ($/share) [3]	1.88	1.08	2.08	1.51	0.84
Financial Position					
Total Assets [1]	17,982	17,079	14,493	12,339	7,703
Long-Term Debt [4]	4,610	4,618	3,630	4,214	2,470
Shareholders' Equity	5,449	4,614	3,961	2,892	2,131
Capital Investment, including Acquisitions	3,401	3,408	2,638	4,264	1,432
Dividends per Common Share ($/share) [3,5]	0.10	0.10	0.10	0.10	0.08
Common Shares Outstanding (thousands) [3]	528,305	525,026	522,281	516,798	502,424

Notes:

1. *In 2004, production declined from our maturing assets in Yemen at Masila, in Canada and in the US Gulf of Mexico Shelf. In late 2004, we acquired North Sea assets and began production from Block 51 in Yemen. In 2005, we sold producing properties in Canada and suffered hurricane-related downtime in the Gulf of Mexico. A full year's production from the North Sea and Block 51 in Yemen offset declines caused by these events. In early 2007, the Buzzard field came on stream and offset declines from Masila in Yemen.*
2. *During 2003, we sold non-core conventional light oil assets in southeast Saskatchewan in Canada producing 9,000 bbls/d. In late 2004, we concluded production from our Buffalo field, offshore Australia, as anticipated. In the third quarter of 2005, we sold Canadian conventional oil and gas properties in Saskatchewan, British Columbia and Alberta producing 18,300 bbls/d. The results of these operations have been shown as discontinued operations.*
3. *Our shareholders approved a split of our issued and outstanding common shares on a two-for-one basis at our annual and special meeting on April 26, 2007. All common share and per common share amounts presented have been retroactively restated to reflect this share split.*
4. *In December 2004, we drew US$1.5 billion on unsecured acquisition credit facilities to finance the purchase of North Sea assets. The remainder of the purchase price was funded from cash on hand. The acquisition credit facility was repaid in 2005 with proceeds from the issuance of US$1.04 billion in senior notes in the first quarter and from asset dispositions in the third quarter. Our long-term debt increased in 2006 as a result of our capital investments, primarily at Buzzard and Long Lake. In May 2007, we issued US$1.5 billion of senior notes with US$250 million maturing in 10 years and US$1,250 million maturing in 30 years. In June 2007, we filed a universal base shelf prospectus in the US and Canada allowing us to potentially raise US$2.5 billion of debt, equity or other hybrid securities, should the need arise.*
5. *Quarterly dividends were increased to 2.5¢ per share in the fourth quarter of 2003.*

management's **discussion**

With significant production growth and strong oil prices, cash flow from operating activities reached a record $2.8 billion.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 21 to the Consolidated Financial Statements. The date of this discussion is February 13, 2008.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities include our Syncrude activities since the product produced from Syncrude competes in the oil and gas market. Oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

Notes:

1. Investors should read the Special Note Regarding Forward-Looking Statements on Page [illegible]

2. Canadian investors should read the Special Note to Canadian Investors on page 76 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

EXECUTIVE SUMMARY

(Cdn$ millions)	2007	2006	2005
Net Income	1,086	601	1,140
Earnings per Common Share, Basic ($/share)	2.06	1.15	2.19
Cash Flow from Operating Activities	2,830	2,374	2,143
Production before Royalties (mboe/d) [1]	254	212	242
Production after Royalties (mboe/d)	207	156	173
Capital Investment, including Acquisitions	3,401	3,408	2,638
Net Debt [2]	4,404	4,730	3,639
Average Foreign Exchange Rate (Canadian to US dollar)	0.93	0.88	0.83
Proved Oil and Gas Reserves before Royalties (mmboe) [3]	734	725	468
Proved Oil and Gas Reserves after Royalties (mmboe) [3]	650	637	393
Proved Syncrude Reserves before Royalties (mmboe) [3]	324	324	318
Proved Syncrude Reserves after Royalties (mmboe) [3]	267	274	264

Notes:

1 *Production before royalties reflects our working interest before royalties and includes production of synthetic crude oil from Syncrude. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.*

2 *Long-term debt and short-term borrowings less cash and cash equivalents.*

3 *Includes developed and undeveloped proved reserves as at December 31.*

Our strategy is to grow long-term value for shareholders responsibly. We started to monetize this value by bringing Buzzard on stream early in 2007 and expect more to follow as Ettrick and the first phase of Long Lake come on stream in 2008. We also added value by increasing our reserves and capturing additional acreage in attractive growth areas like the US Gulf of Mexico, Norway, and shale gas and oil sands in western Canada. Higher net income and cash flow from operating activities in 2007 were due to a 33% increase in production after royalties (20% increase before royalties) and strong commodity prices. Although WTI rose 9% from 2006, a stronger Canadian dollar limited the increase in our realized crude oil prices. This was offset by changes in our production mix as we are transitioning to higher-value crude oil from Buzzard. Our average realized oil and gas price increased 9% over last year to $68.46/boe.

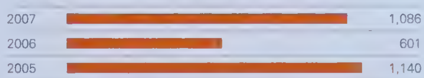
Our share of production from Buzzard averaged more than 64,000 boe/d in 2007. While commissioning of all systems took longer than expected, the facilities have produced as high as 220,000 boe/d (95,000 boe/d net to us) during the year, higher than originally expected. Looking forward, with a full year of Buzzard on stream and new production expected from Ettrick and Long Lake, we expect 2008 net production to average between 220,000 and 240,000 boe/d (260,000 and 280,000 before royalties).

Net income in 2007 includes impairment expense of $366 million (before tax) related to four properties in the Gulf of Mexico as required by successful efforts accounting for oil and gas. The majority of the expense relates to the Aspen deep-water field where recent unsuccessful development drilling and steep production declines resulted in negative reserve revisions. Unsuccessful recompletions, production declines and disappointing development results on the shelf reduced reserves and generated the remainder of the impairment expense.

We invested almost half of our 2007 capital on major development projects at Long Lake and Ettrick. In the Athabasca oil sands, we invested $1.1 billion in Long Lake Phase 1 and future phases. We are currently injecting steam into the reservoir through all well pads and the SAGD facilities are operating as expected. Upgrader construction is 97% complete and commissioning is progressing well. The upgrader is expected to come on stream mid 2008. In the North Sea, we brought additional development wells on stream at Buzzard and made significant progress on Ettrick. We also invested $130 million in building our prospect inventory in the US Gulf of Mexico deepwater and Canadian shale gas.

Cash Flow from Operating Activities
(Cdn$ millions)

Net Income
(Cdn$ millions)



Our 2007 exploration program was focused primarily in the Gulf of Mexico and the North Sea. We were successful with discoveries in the Gulf at Vicksburg and on the shelf, and at Selkirk and Kildare in the North Sea. We also successfully appraised prior discoveries at Longhorn in the Gulf of Mexico and Golden Eagle in the North Sea. Unfortunately, we did not advance our Knotty Head discovery in the Gulf as a suitable drilling rig was not available.

With the weaker US dollar, our net debt decreased over $300 million from last year. Our US-dollar denominated debt was lower by $800 million when translated to Canadian dollars. This was partially offset by capital investment that exceeded our cash flow from operations.

Throughout 2007, the US dollar continued to weaken relative to the Canadian dollar. Our sales revenue is denominated in, or referenced to, US dollars and, as a result, our reported Canadian dollar revenues are lower as the US dollar weakens. On the other hand, our US-dollar capital spending and operating costs are also lower when translated to Canadian dollars, as well as our US denominated debt. Overall, the weaker US dollar reduced our 2007 cash flow from operating activities by $255 million and net income by $122 million.

During 2007, our proved oil and gas and Syncrude reserves additions replaced 109% of our oil and gas and Syncrude production (108% after royalties) as shown below:

(mmboe)	Before Royalties	After Royalties
Production		
Oil and Gas	85	68
Syncrude	8	7
Total	**93**	**75**
Reserve Changes excluding Production		
Oil and Gas	94	81
Syncrude	8	–
Total	**102**	**81**

Two-thirds of our additions relate to our key projects at Buzzard in the North Sea and Long Lake in the Athabasca oil sands. Other additions came from successful exploration and development activities in virtually all areas of our operations, somewhat offset by lower production performance and unsuccessful activities at Aspen and the shelf in the Gulf of Mexico. We also added 10 mmboe (8 after royalties), net of dispositions, from acquisitions and swaps primarily in the Gulf of Mexico.

CAPITAL INVESTMENT

(Cdn$ millions)	Estimated 2008	2007	2006
Major Development	700	1,479	1,849
Early Stage Development	400	162	123
New Growth Exploration	600	573	491
Core Asset Development	600	1,069	748
Total Oil & Gas and Syncrude	2,300	3,283	3,211
Marketing, Corporate, Chemicals and Other	100	118	197
Total Capital	**2,400**	**3,401**	**3,408**

Our strategy and capital programs are focused on growing long-term value for our shareholders responsibly. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- exploration projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning toward less mature basins and unconventional resources. Key focus areas include the North Sea, Athabasca oil sands, Canadian CBM and shale gas, Gulf of Mexico deep waters, offshore West Africa and the Middle East—areas we believe have attractive fiscal terms, significant remaining opportunity, and where we have a competitive advantage.

In 2007, we invested $3.4 billion in capital expenditures, mostly in major development projects and long cycle-time exploration. In 2008, we plan to invest $2.4 billion, which is $1 billion lower than 2007 as we incurred most of the capital costs for the first phase of Long Lake. About half of the 2008 capital investment will be focused on major and early stage development projects, 29% on core assets to sustain production and provide cash flow, and the remainder to drill high-impact exploration wells and continue building our acreage.

2007 Capital

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	1,025	108	6	–	1,139
United States	28	2	275	488	793
United Kingdom	323	–	119	274	716
Canada	103	21	117	125	366
Yemen	–	–	12	124	136
Other Countries	–	31	44	22	97
Syncrude	–	–	–	36	36
	1,479	162	573	1,069	3,283
Marketing, Corporate and Other	–	–	–	118	118
Total Capital	**1,479**	**162**	**573**	**1,187**	**3,401**
As a % of Total Capital	43%	5%	17%	35%	100%

2008 Estimated Capital

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	400	150	–	–	550
United States	80	–	225	85	390
United Kingdom	200	20	210	325	755
Canada	20	50	70	80	220
Yemen	–	–	–	65	65
Other Countries	–	180	95	–	275
Syncrude	–	–	–	45	45
	700	400	600	600	2,300
Marketing, Corporate and Other	–	–	–	100	100
Total Capital	**700**	**400**	**600**	**700**	**2,400**
As a % of Total Capital	29%	17%	25%	29%	100%

Synthetic

In 2007, we invested a total of $1.1 billion to develop our insitu oil sands resource. This included approximately $1 billion on the first phase of Long Lake, $591 million of which related to the upgrader.

Long Lake continues to progress well towards first production of premium synthetic crude in mid 2008. We are currently injecting steam into the reservoir through all well pads. We have started converting wells to SAGD operation and we have also recently started up our first cogeneration unit which allows us to produce electricity and build our steaming capacity. The second cogeneration unit is expected to start up towards the end of the first quarter. We expect bitumen production to ramp up in the spring and we are on track to have sufficient bitumen production for the start up of the upgrader. The bitumen production capacity of the SAGD facilities is approximately 72,000 bbls/d (36,000 bbls/d net to us).

In 2007, we invested a total of $1.1 billion to develop our insitu oil sands resource.

At the end of 2007, construction of the upgrader was 97% complete and commissioning is progressing well. We have turned over the hydrocracker, the OrCrude™ unit and all main plant utilities to operations. The gasifier and air separation unit were essentially mechanically complete at year end 2007, and we are completing final electrical and insulation work. Construction of the sulphur recovery unit is expected to be completed by the end of the first quarter, in sufficient time for first production of synthetic crude oil in mid 2008. Production of premium synthetic crude will ramp up to full rates over a 12 to 18 month period following initial upgrader start up. The upgrader is designed to produce approximately 60,000 bbls/d (30,000 bbls/d net to us) of premium synthetic crude.

The total cost estimate for the Project remains unchanged at between $5.8 billion and $6.1 billion (between $2.9 billion and $3.05 billion net). We are planning to increase synthetic crude oil production as we sequentially develop our lands with additional 60,000 bbls/d (30,000 bbls/d net) phases using the same technology and design as Long Lake.

United States

At Longhorn, where we have a 25% working interest, we completed drilling an appraisal well which exceeded our expectations and encountered hydrocarbons in multiple sands. The Longhorn project has been sanctioned and development will consist of subsea tie-backs to a host facility with first production expected in 2009.

In late 2007, we invested $104 million to acquire three producing deep-water properties at Garden Banks Block 205 and Green Canyon Blocks 137 and 6/50. These properties are currently producing approximately 3,000 boe/d. Drilling of a development well at Green Canyon 6/50 is underway and we expect production from this well to add up to 5,000 boe/d to our 2008 annual volumes.

At Knotty Head, we continue to pursue rig availability in the short term to allow us to spud an appraisal well. To date, we have evaluated two rigs but determined that these rigs did not have the drilling capability required. We have contracted two new deep-water drilling rigs that are scheduled to arrive in mid 2009 and 2010, respectively.

Our 2007 exploration program resulted in discoveries at Vicksburg, Mississippi Canyon 72 and South Marsh Island 257. The Vicksburg discovery well, located on De Soto Canyon Block 353 in the Eastern Gulf of Mexico, was drilled to a depth of approximately 25,400 feet and encountered hydrocarbons. Core was recovered from the well and studies are underway to assess the potential productivity. Additional drilling in the area is planned in 2008. We have a 25% non-operated working interest in this discovery. Shell is the operator with a 57.5% working interest and Plains Exploration & Production Company holds the remaining 17.5% interest. In the same area, we participated in a discovery well in 2003 at Shiloh located on DeSoto Canyon Block 269, that was drilled by Shell. This well was drilled to a total depth of approximately 24,000 feet, encountered hydrocarbons and was temporarily abandoned pending further evaluation of the area. We have a 20% non-operated working interest in Shiloh.

In the Eastern Gulf of Mexico, where the discoveries at Shiloh and Vicksburg are located, we have identified a number of additional exploration opportunities in the region. We also have the right to extend our acreage position through the

acquisition of working interests in various blocks recently awarded to Shell as a result of their participation in Lease Sale 205 late last year.

Our other discoveries at Mississippi Canyon 72 and South Marsh Island 257 are currently being evaluated. Both discoveries are expected to come on production in 2008. We have working interests of 33% and 34.5% respectively in these discoveries.

United Kingdom

In the UK, we invested over $700 million in 2007. This included $160 million at Buzzard where we drilled six development wells. Our Ettrick development in the North Sea is progressing well towards first oil mid 2008. In 2007, we invested approximately $260 million. This development will utilize a leased floating production, storage and off-loading vessel (FPSO) designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas. We expect to ramp up to production of approximately 30,000 boe/d gross by the end of the year. We operate Ettrick with an 80% working interest. We have also identified a number of exploration opportunities in the immediate area that could be future tie-backs to Ettrick. We have plans to drill at least two of these opportunities this year.

Elsewhere, we are assessing development alternatives for our Golden Eagle discovery where we have a 34% operated working interest. At Kildare, we are planning to drill an appraisal well this year. The discovery well was drilled to a depth of approximately 14,100 feet. We also completed an appraisal well at Selkirk which confirmed commercial quantities of hydrocarbons and we are currently reviewing development options. We have a 38% operated working interest here.

At Bugle, we are currently drilling an appraisal well. Well results are still being analyzed but initial test results are encouraging. We have a 41% working interest here.

Canada

In Canada, we are developing the first commercial coalbed methane (CBM) project in the Mannville coals. In 2007, we invested $173 million in exploration and development activities on our CBM lands.

In northeast British Columbia we have a material land position of approximately 190 net sections in an emerging Devonian shale gas play which has the potential to be one of the most significant shale gas plays in Canada. We are currently evaluating this opportunity with a program of drilling, completing and production testing.

Yemen

Yemen remains a significant asset for us and is expected to generate approximately 15% of our projected cash flow in 2008. In 2007, we invested $136 million and in 2008, we expect to produce between 50,000 and 55,000 boe/d before royalties here.

Other Countries

The Usan field development, located in Nigeria on offshore Block OPL -222, continues to move forward. We expect the project to advance to the execution phase shortly and this will facilitate the award of the major deep-water facilities contracts. The project will have the ability to process an average of 180,000 bbls/d of oil during the initial production plateau period through a new FPSO with a two million barrel storage capacity. We have a 20% interest in exploration and development on this block.

Syncrude

At Syncrude, we invested $36 million in 2007. In 2008, we have turnarounds scheduled in the second and third quarters and expect annual production of between 20,000 and 25,000 bbls/d.

2007 Capital

1 *Mainly Long Lake*
2 *Marketing, Corporate and Other.*

2008 Estimated Capital

1 *Mainly Long Lake*
2 *Marketing, Corporate and Other*

FINANCIAL RESULTS

Year-to-Year Change in Net Income

(Cdn$ millions)	2007 vs 2006	2006 vs 2005
Net Income for 2006 and 2005 [1]	**601**	**1,140**
Favourable (unfavourable) variances: [2]		
Production Volumes, After Royalties		
Crude Oil	1,354	(245)
Natural Gas	(17)	(55)
Change in Crude Oil Inventory	22	(74)
Total Volume Variance	1,359	(374)
Realized Commodity Prices in Canadian Dollars		
Crude Oil	308	325
Natural Gas	(24)	(133)
Total Price Variance	284	192
Operating Expense		
Conventional Oil & Gas	(178)	13
Syncrude	(21)	(35)
Total Operating Expense Variance	(199)	(22)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas and Syncrude	(636)	(48)
Other	(7)	4
Total Depreciation, Depletion, Amortization and Impairment Variance	(643)	(44)
Exploration Expense	36	(111)
Energy Marketing Contribution	(373)	336
Chemicals Contribution	27	(12)
General and Administrative Expense	181	254
Interest Expense	(115)	44
Current Income Taxes	(66)	(29)
Future Income Taxes	(43)	(549)
Other		
Block 51 Settlement	151	(151)
Business Interruption Insurance Proceeds	(154)	152
Gains from Divestiture Programs	–	(418)
Increase (Decrease) in Fair Value of Crude Oil Put Options	(32)	185
Other	72	8
Net Income for 2007 and 2006	**1,086**	**601**

Notes:

1 2005 includes results of discontinued operations (see Note 14 to our Consolidated Financial Statements).

2 All amounts are presented before provision for income taxes.

Significant variances in net income are explained in the sections that follow.

OIL & GAS AND SYNCRUDE

Production

	2007		2006		2005	
	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Oil and Liquids (mbbls/d)						
United Kingdom	81.2	81.2	16.9	16.9	12.6	12.6
Yemen	71.6	39.8	92.9	51.8	112.7	60.6
Canada [2]	17.1	13.4	20.0	15.8	29.2	22.6
United States	16.4	14.5	17.0	15.0	22.2	19.6
Other Countries	6.2	5.7	6.3	5.7	5.6	5.1
Syncrude (mbbls/d) [3]	22.1	18.8	18.7	16.9	15.5	15.3
	214.6	173.4	171.8	122.1	197.8	135.8
Natural Gas (mmcf/d)						
United Kingdom	16	16	20	20	23	23
Canada [2]	118	98	108	91	124	101
United States	101	86	111	94	116	99
	235	200	239	205	263	223
Total (mboe/d)	**254**	**207**	**212**	**156**	**242**	**173**

Notes:

1 *We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies*

2 *Includes the following production from discontinued operations. See Note 14 to our Consolidated Financial Statements.*

	2007	*2006*	*2005*
Before Royalties			
Oil and Liquids (mbbls/d)	–	–	*6.7*
Natural Gas (mmcf/d)	–	–	*24*
After Royalties			
Oil and Liquids (mbbls/d)	–	–	*5.3*
Natural Gas (mmcf/d)	–	–	*17*

3 *Considered a mining operation for US reporting purposes.*

2007 vs 2006—Higher production increased net income by $1,359 million

Production before royalties increased 20% from 2006, 33% after royalties. This increase reflects the start up of Buzzard in early 2007, offset by declines in our maturing Yemen fields.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2006 Production	212	156
Production Changes		
United Kingdom	64	64
Yemen	(21)	(12)
Syncrude	3	2
Other	(4)	(3)
2007 Production	**254**	**207**

In 2008, we expect additional production growth over 2007 and expect production to range from 220,000 to 240,000 boe/d (260,000 and 280,000 boe/d before royalties). Increases are expected from a full year of Buzzard, and from the mid-year start up of Long Lake Phase 1 and the North Sea Ettrick development.

Production volumes discussed in this section represent our working interest before royalties.

United Kingdom

The addition of high-margin, royalty-free Buzzard volumes increased North Sea production by 64,000 boe/d (net to us), up 300% from last year. Buzzard came on stream January 7, 2007 and ramped up to peak production during the year. While the ramp-up was slower due to pipeline restrictions and the reliability of the acid gas removal system, we regularly exceeded initial expectations. Buzzard has safely produced as high as 220,000 boe/d (95,000 net to us), higher than originally expected. We are proceeding with work to add additional sweetening facilities to handle higher levels of hydrogen sulphide, and are reviewing debottlenecking opportunities to increase the processing capacity of the platform. We had ten wells on stream at Buzzard at the end of 2007.

Buzzard came on stream in January 2007 and has safely produced as high as 220,000 boe/d (95,000 net to us), 10% above expectations.

Scott/Telford produced 16,500 boe/d, comparable with 2006 rates. During the second quarter of 2007, we increased our interests in the Scott and Telford fields by 0.9% and 17.4%, respectively. The additional production we purchased was offset by natural declines and downtime caused by increased maintenance activity. Farragon produced 2,600 boe/d during the year, 30% lower than 2006 as a result of natural declines. In the fourth quarter, production from our non-operated Duart field came on stream.

In 2008, we plan to drill additional development wells at Buzzard and Scott/Telford and we anticipate bringing production on stream at Ettrick mid year. We expect production from the North Sea to average between 95,000 and 115,000 boe/d in 2008. Our expected production for 2008 reflects some provision for planned and unplanned downtime.

Yemen

Yemen production declined 23% from 2006. Masila production decreased 19%, consistent with expectations. In 2007, we drilled 18 development wells and 12 sidetrack wells. Strong initial rates from new wells, combined with well optimizations and reservoir management, helped to minimize expected production declines. Base declines at Masila are expected to continue as most of the development opportunities were previously drilled to maximize reserve and capital recoveries under the production sharing agreement. We continue to concentrate capital on maximizing recoveries, and therefore economic returns, from our existing wells before our contract expires in 2011. In 2008, we plan to drill 10 development wells and continue to optimize well performance.

On Block 51 in Yemen, production from the East Al Hajr field declined 35% as a result of natural declines and fewer development wells. We drilled 13 development wells in 2007 as compared to 24 the year before. Five development wells are planned for 2008.

Substantial value still remains in our Yemen assets as we expect to generate approximately 22% of the total project free cash flow from Masila over the remaining life of the contract. We expect our share of Yemen production to average between 50,000 and 55,000 boe/d in 2008.

Canada

Production in Canada decreased 3% from the previous year. CBM production rates continue to increase as our wells in the Fort Assiniboine area de-water and we bring additional development wells and facilities on stream. We are optimizing the operation of the CBM development wells to maximize up-time and efficiency. Declines in our natural gas properties in the Medicine Hat region have been more than offset by infill drilling, and future opportunities remain in the region for additional infill drilling. Our capital investment in heavy oil properties continues to partially offset natural declines. At our Balzac gas facility, north of Calgary, we completed a turnaround mid year, which required production to be shut-in for approximately 48 days.

In 2008, we expect production from Canada to average between 45,000 and 50,000 boe/d, with new premium synthetic crude oil at Long Lake expected mid year and higher CBM volumes.

2007 Production before Royalties

2006 Production before Royalties

United States

Gulf of Mexico production decreased 6%, or about 2,300 boe/d from 2006. At Aspen, production increased 1,500 boe/d from the previous year. Natural declines in the field, and maintenance and weather-related shut-ins of the non-operated processing facilities partially offset production from new development wells. In late 2006, we brought the Aspen 5 development well on stream; however, decline rates in this well were higher than expected. We previously identified other opportunities at Aspen and completed a sidetrack mid year to exploit deeper sands. While we were encouraged by well log data indicating thick pay zones in the sidetrack, well deliverability rates could not be sustained. This likely indicates barriers within this section of the reservoir that are not present elsewhere. The other Aspen wells continue to produce in line with expectations; however, we expect field production to continue declining as a result of increasing water cuts and reservoir depletion.

Gunnison production was approximately 3,800 boe/d or 36% lower than last year due to natural declines and mechanical issues in one high volume well. Gunnison accounted for 20% of our production from the Gulf of Mexico during the year and we expect to bring another development well on stream in 2008. The Wrigley development came on stream early July but gas production was restricted by limited heat exchanger capability on the non-operated processing facility resulting in an annualized average production rate of 7 mmcf/d in 2007. We are currently working with the facility operator and expect production to increase to peak rates of 24 mmcf/d (net to us) in 2008. Late in the third quarter, we acquired three deep-water properties producing approximately 3,000 boe/d. We expect to drill an additional development well at one of these properties in early 2008.

On the shelf, our mature assets continue to be impacted by natural declines, and limited workover and recompletion activity. Declines at Vermilion 76, Eugene Island 18 and West Cameron 170 were only partially offset by Vermillion 340 production that was restored in early 2007. Vermillion 340 was shut-in since 2005 due to damage to the sub-surface pipeline system caused by hurricanes in 2005. Our shelf production declined 13% from 2006.

In 2008, we expect total production from the Gulf of Mexico to average between 25,000 and 30,000 boe/d.

Other Countries

Production from Guando in Colombia was consistent with 2006. We sustained production rates by maintaining reservoir pressure through an active waterflood program and by drilling additional infill wells. We expect to maintain current production rates in 2008; however, our interest in the field will decrease to 10% once the field has produced 60 million barrels, likely in 2009.

Syncrude

At Syncrude, production averaged 22,060 boe/d, up 18% from 2006 as the Stage 3 expansion contributed a full year of production. Despite this increase, production was lower than expected as Coker 8-3 had a utilization rate of less than 70% over the year because of a variety of operating issues with the new equipment. After an extended turnaround on the LC Finer and Coker 8-3 in the second quarter of 2007, the Coker processed bitumen at expected capacity until early October when it was temporarily shut in due to coke build up. In December, production was partially reduced for four days due to a fire in Coker 8-3's environmental precipitators. In early 2008, production at Syncrude was temporarily suspended for six days due to an upset in the amine and fuel gas system that was brought on by extremely cold weather conditions.

Strong realized prices for our production have enabled us to fully recover capital costs at Syncrude including costs associated with the Stage 3 expansion. Consequently, our Syncrude royalties increased from a 1% gross revenue royalty to a 25% net revenue royalty, beginning in 2006. This translates into lower after royalty production relative to our working interest production volumes. The Alberta government is currently negotiating with the Syncrude owners to amend the existing royalty agreement, which is in place until 2016. This could result in Syncrude moving to the proposed royalty framework, which features higher royalty rates, before January 2016 in exchange for other concessions.

In 2008, we expect our share of Syncrude production to average between 20,000 and 25,000 bbls/d.

2006 vs 2005—Lower production decreased net income by $374 million

Production before royalties decreased 12% from 2005, 10% after royalties. Our 2006 production excluded volumes from our Canadian oil and gas properties that were sold in the third quarter of 2005. Removing the impact of these property dispositions, production before and after royalties decreased 8% and 5%, respectively. Decreases were caused by natural declines at mature fields in Yemen and at Aspen in the Gulf of Mexico.

Commodity Prices

	2007	2006	2005
Crude Oil			
West Texas Intermediate (WTI) (US$/bbl)	72.31	66.22	56.58
Benchmark Differentials[1] (US$/bbl)			
Heavy Oil	23.44	21.79	20.82
Mars	5.67	7.34	6.59
Masila	0.50	3.00	5.71
Dated Brent	(0.21)	1.08	2.20
Producing Assets (Cdn$/bbl)			
Yemen	76.29	71.57	62.07
Canada	44.07	42.79	40.51
United States	69.83	65.80	57.63
United Kingdom	76.30	71.19	60.55
Other Countries	71.29	66.09	59.96
Syncrude	79.76	72.32	71.00
Corporate Average (Cdn$/bbl)	73.43	67.50	58.98
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	7.12	6.99	8.99
AECO (Cdn$/mcf)	6.26	6.62	8.04
Producing Assets (Cdn$/mcf)			
Canada	6.32	6.49	7.51
United States	7.80	7.86	10.56
United Kingdom	4.71	7.43	7.86
Corporate Average (Cdn$/mcf)	6.81	7.18	8.89
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	**68.46**	**62.92**	**57.97**
Average Foreign Exchange Rate—Canadian to US Dollar	0.9304	0.8818	0.8253

Note

1 These differentials are a discount/(premium) to WTI.

2007 vs 2006—Higher realized prices increased net income $284 million

Average WTI and Dated Brent in US dollars were 9% and 11% higher, respectively, from the prior year, and our average realized crude oil price increased 9% to $73.43/bbl. Our higher average realized price reflects the change in production mix with the addition of new high quality Buzzard production. This change helped to offset the impact of the weaker US dollar on our Canadian dollar realized prices. Our realized natural gas price fell 5% from 2006 as a result of the stronger Canadian dollar, despite NYMEX increasing 2% in the same period. The weaker US dollar reduced net sales by approximately $225 million, and reduced our realized crude oil and natural gas prices by approximately $3.20/bbl and $0.30/mcf, respectively, as compared to 2006.

Crude Oil Reference Prices

Crude oil prices remained strong in 2007. Crude oil prices climbed steadily throughout the year, with WTI ranging from a low of US$49.90/bbl early in the year to US$95.98/bbl in December. In early 2008, WTI broke through US$100/bbl in intra-day trading but has since slipped to about US$90/bbl on fears of a US recession. The main drivers of the high prices last year were concerns over supply resulting from geopolitical tensions around the world, strong global demand, declining inventory levels and a weakening US dollar.

Geopolitical risk continued to be an underlying theme throughout 2007. In the Middle East, on-going tensions between the US and Iran over its uranium enrichment program led to fears that it would escalate to potential US action against Iran and a reduction in oil exports. Conflict also escalated between Turkey and Kurdish rebels in Northern Iraq, where a substantial portion of the country's oil production is located. Supply outages in Nigeria caused by continued violence, and nationalization of Venezuela's energy industry also contributed to higher prices and market volatility.

Global demand growth for crude oil continues to be robust. Demand from China, the world's second largest oil consumer, India, Russia and the Middle East grew from last year whereas global supply increased marginally. There are concerns over supply from politically unstable locations such as Nigeria, Iran and Iraq, some of the world's major oil producers and exporters. A sustained decline in inventories also contributed to strong oil prices. Crude oil inventories at the end of 2007 were at their lowest levels in the last five years.

A steadily weakening US dollar helped fuel the rise of crude oil prices to an all-time nominal high since global crude oil is denominated in US dollars. Weak equity markets also re-directed investment into the financial commodity markets, increasing volatility.

Crude Oil Differentials

In Canada, heavy crude oil differentials averaged US$23.44/bbl (32% of WTI) for the year, compared to US$21.79/bbl (33% of WTI) in 2006. Differentials were narrower than usual at the beginning of the year as OPEC cuts from late 2006 tended to be heavy oil, thereby increasing prices for heavier crude. As we headed into the summer asphalt season, we expected a seasonal narrowing. However, a major fire at BP's Whiting refinery in March curtailed its ability to process heavy oil for the remainder of the year reducing the demand for Canadian heavy crude by 100,000 barrels a day. Late in the year, the differentials widened substantially due to pipeline constraints until a shutdown at the Albian upgrader in the Athabasca oil sands freed up pipeline space. In December, the heavy oil differential improved from $45/bbl to $25/bbl as a result of weaker WTI prices and the Albian upgrader incident. Heavy oil prices are expected to weaken again in January and February once the Albian upgrader is back on stream.

The Brent/WTI differential strengthened during 2007 with Brent trading at a premium of US$0.21/bbl compared to a discount of US$1.08/bbl in 2006. The Brent index is relevant for us as approximately 80% of our current crude production is priced based on Brent. WTI traded at a discount to Brent for almost half of the year. Regional issues, such as an overabundance of crude in local storage around the Cushing, Oklahoma area where WTI is priced and the limited ability to move that crude to world markets caused WTI to trade at lower prices than other international grades of crude oil. By comparison, Brent prices were strong as multiple transportation options allow it to remain a global crude oil. However, WTI regained its strength and traded at a premium to Brent during the latter part of the year.

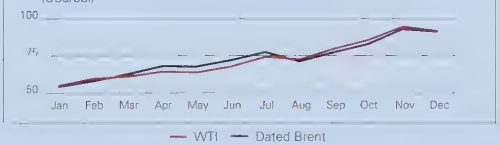
The US Gulf Coast Mars differential narrowed, averaging US$5.67/bbl in 2007 compared to US$7.34/bbl in 2006. Since Mars can be moved globally, it competes with international crudes and was not readily affected by the pipeline constraints at Cushing earlier in the year which depressed WTI.

The Yemen Masila differential narrowed substantially relative to WTI during 2007, averaging US$0.50/bbl compared to US$3.00/bbl last year. Yemen Masila traded at a premium to WTI in the summer, reflecting the impact of stronger Brent pricing since Masila crude is priced off Brent. As WTI regained its strength relative to Brent in the fall, the Yemen Masila differential traded at a discount to WTI for the remainder of the year.

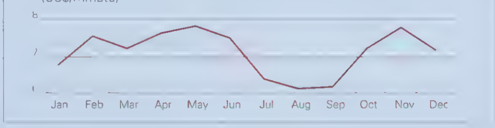
Natural Gas Reference Prices

NYMEX natural gas prices averaged US$7.12/mmbtu, compared to US$6.99/mmbtu in 2006. In January 2007, gas prices were unusually soft at the peak of the withdrawal season as January experienced the highest global temperature on record for this time of year. However, natural gas prices rebounded in the following months as a result of strong crude oil prices, technical trading in financial markets and cold weather in several key North American natural gas consuming regions. Natural gas prices weakened during the summer and autumn seasons reflecting higher storage levels that were approaching the top of the North American five-year average. The high storage levels were caused by LNG cargoes being diverted to North America from weak European markets, mild summer weather and a quiet hurricane season in the Gulf of Mexico.

2007 Monthly Average Oil Price
(US$/bbl)



2007 NYMEX Monthly Average Natural Gas Price
(US$/mmbtu)



2006 vs 2005—Higher realized prices increased net income by $192 million

Crude oil prices remained strong for most of 2006, with WTI finishing the year at US$61.05/bbl, roughly where it began. The steady decline in crude prices from August to the end of the year was largely driven by warm weather, above average crude oil inventories, concerns over the US economy, the perceived reduction of geopolitical tensions in the Middle East and institution-led sell offs in the crude oil markets.

Natural gas prices averaged US$6.99/mmbtu, 22% below 2005 levels. NYMEX reached record price and volatility levels in late 2005, driven mainly by the impact of hurricanes Katrina and Rita and speculation around the 2005/2006 North American winter season. In 2006, mild January temperatures experienced in several key North American natural gas consuming regions resulted in a weaker NYMEX. This created a significant gas storage overhang. Prices remained soft throughout the year reflecting high storage levels, an uneventful hurricane season and a mild 2006/2007 winter prediction due to the warming effect of El Nino.

The full impact of the increase in WTI was not reflected in our higher realized crude oil price as the Canadian dollar strengthened relative to the US dollar. The impact of the weaker US dollar was offset by narrower crude oil differentials. The weaker US dollar reduced net sales by approximately $250 million, and reduced our realized crude oil and natural gas prices by approximately $4.85/bbl and $0.50/mcf, respectively as compared to 2005.

Operating Expenses

	2007		2006		2005	
(Cdn$/boe)	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties
Conventional Oil and Gas						
Yemen	6.56	12.00	4.45	8.11	3.63	6.75
Canada	12.91	15.93	10.31	12.73	8.21	10.34
United States	8.43	9.69	8.17	9.45	6.35	7.33
United Kingdom	6.94	6.94	11.28	11.28	14.90	14.90
Other Countries	3.45	3.76	2.87	3.13	5.55	6.08
Average Conventional	7.89	9.75	6.95	9.69	6.03	8.70
Synthetic Crude Oil						
Syncrude	25.80	30.32	27.53	30.43	26.95	27.22
Average Oil and Gas	9.45	11.63	8.77	11.96	7.36	10.34

Note:

1 Operating expenses per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2007 vs 2006—Higher operating expenses decreased net income by $199 million

Our oil and gas operating costs increased $199 million from 2006 primarily as a result of Buzzard coming on-stream in early 2007 and higher Syncrude production. Our production mix also changed from last year as a result of this production, altering our average unit cost. Operating costs at Buzzard are lower than our corporate average, reducing our corporate average by $1.58/boe. However, the higher-cost Syncrude barrels increased our corporate average by $0.74/boe.

At Masila in Yemen, operating costs increased with higher service rig activity and maintenance programs. These costs are necessary to minimize production declines and maximize the recovery of the remaining reserves, given the maturity of the field. The higher costs and lower production increased our corporate average by $0.57/boe. Similarly at Block 51, our operating expenditures were higher as additional service rig activity and higher water handling, fuel and equipment costs increased operating expenditures. The higher costs increased our corporate average $0.37/boe. We expect the average per-unit cost to continue to increase in Yemen as production declines.

Canadian production increased our corporate average $0.50/boe during the year as a result of industry cost pressures, the extended Balzac turnaround and lower production. Our heavy oil properties have higher unit operating costs as many of the costs are fixed in nature and heavy oil production is declining. Operating costs have also increased with additional CBM wells coming on-stream at Fort Assiniboine. Unit operating costs are initially higher as we de-water the wells to stimulate gas production. We expect our CBM operating costs to decrease over time as the wells de-water, reliability improves and gas production increases.

In the Gulf of Mexico, while total operating costs remained consistent year over year, lower production increased our corporate average by $0.18/boe. During 2007, industry pressures increased costs and we performed additional downhole and surface maintenance activity to maintain production. However, these costs had minimal impact on our corporate average when compared to last year as our 2006 costs included extended maintenance and turnaround activity at Eugene Island on the shelf.

Operating costs at Buzzard are low, reducing our corporate average by $1.58/boe.

In the UK North Sea, our Scott/Telford costs increased our corporate average by $0.33/boe. During the year, our total operating expenditures increased as we performed maintenance and work overs on the platform and producing wells, including repairing turbines and improving water injection facilities.

Lower Syncrude operating costs reduced our corporate average by $0.16/boe, and were 6% lower than 2006 as the impact of the higher production from the expansion completed in 2006 was only partially offset by increased maintenance costs. In 2007, maintenance and turnarounds on the Coker 8-3 and the LC Finer interrupted production and increased operating costs.

US-dollar denominated operating costs were lower when translated into Canadian dollars, reducing our corporate average $0.26/boe.

2006 vs 2005—Higher operating expenses decreased net income by $22 million

In Yemen, operating costs on a per-unit basis increased as fixed costs from our central processing facilities and increased water handling costs were spread over lower production volumes. Masila increased our corporate average by $0.20/boe, reflecting lower production, increased service rig activity to minimize production declines, and costs to replace a single point mooring system to load oil tankers. Block 51 operating costs increased our corporate average by $0.22/boe, reflecting higher manpower costs, increased water handling costs at the new facilities, maintenance costs associated with equipment repairs and power outages, and increased fuel consumption and fuel prices.

Following the sale of Canadian conventional oil and gas properties in 2005, we had proportionately more heavy oil production, which had higher operating costs than the lighter oil production we sold. Canadian operating costs in 2006 increased our corporate average by $0.18/boe. Operating costs in the Gulf of Mexico increased from 2005 due to industry cost pressures caused by strong commodity prices and the 2005 hurricane season. Lower production volumes and workovers on our shelf properties early in 2006 increased our corporate average by $0.39/boe.

With the sale of Canadian production in 2005, barrels from the North Sea contributed a higher percentage of our total production. As the North Sea had higher operating costs than our average cost per barrel, the change in production mix increased our corporate average by $0.32/boe. This was offset by lower operating costs relative to 2005, as operating expenses in 2005 included repair costs related to turbine failures. This reduced our corporate average by $0.26/boe.

Syncrude increased our corporate average operating costs by $0.72/boe from 2005 as a result of maintenance activities and the coker turnaround during the first quarter of 2006, combined with costs related to start-up of the Stage 3 expansion.

The stronger Canadian dollar decreased our US-dollar denominated operating costs, reducing our corporate average as compared to 2005 by $0.38/boe.

Depreciation, Depletion, Amortization and Impairment (DD&A)

(Cdn$/boe)	2007 Before Royalties[1]	2007 After Royalties	2006 Before Royalties[1]	2006 After Royalties	2005 Before Royalties[1]	2005 After Royalties
Conventional Oil and Gas						
Yemen	8.15	14.92	9.67	17.61	8.56	15.93
Canada	12.46	15.37	11.22	13.84	9.26	11.67
United States[2]	22.64	26.03	16.28	18.84	15.39	17.77
United Kingdom	19.59	19.59	30.22	30.22	33.25	33.25
Other Countries	3.68	4.06	4.30	4.69	6.20	6.79
Average Conventional	14.94	18.47	13.12	18.30	11.78	17.00
Synthetic Crude Oil						
Syncrude	6.59	7.74	4.81	5.32	3.08	3.12
Average Oil and Gas	14.21	17.49	12.38	16.88	11.23	15.77

Notes.

1 DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2 DD&A per boe excludes the impairment charges described in Note 6 of our Consolidated Financial Statements.

2007 vs 2006—Higher oil and gas and Syncrude DD&A decreased net income by $636 million

In 2007, our DD&A expense includes $366 million ($3.96/boe) of impairment expense primarily related to our Aspen, Vermillion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our recent investment in development drilling resulted in negative reserve revisions. While we were encouraged by well log data indicating thick pay zones, well deliverability rates could not be sustained. This likely indicates barriers within this section of the reservoir. At Vermillion 320/340 and West Cameron 170, negative reserve revisions primarily relate to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. The carrying values of these properties were reduced to their estimated fair value.

Production from Buzzard increased our corporate average unit DD&A rate by $1.44/boe. Buzzard costs are higher than our corporate average as they include acquisition and project completion costs. We expect Buzzard unit depletion to decrease over time as we expect to book more proved reserves from production experience and further development drilling. We recognized additional proved reserves at the end of 2006 for our other UK assets, which lowered the corporate average $0.59/boe in 2007.

A reduced capital program and slower recovery of capital costs paid on the Yemen government's behalf decreased our corporate average DD&A rate by $0.15/boe.

Depletion of our Canadian assets increased our corporate average by $0.24/boe reflecting the timing of reserve bookings from our CBM projects in central Alberta, and land acquisitions in 2006. As our new CBM wells progress through the de-watering stage and production increases, we expect to recognize additional proved reserves which will reduce our unit depletion rate.

In the Gulf of Mexico, unsuccessful development drilling at Aspen and on the shelf increased our capital base, increasing our corporate average rate by $1.29/boe.

Syncrude DD&A includes costs to develop the Stage 3 expansion that came on stream in mid 2006, which increased our corporate average by $0.21/boe.

The strong Canadian dollar relative to the US dollar decreased our corporate average DD&A rate by $0.53/boe as our US and international depletion is denominated in US dollars.

2006 vs 2005—Higher oil and gas DD&A decreased net income by $48 million

Our 2006 DD&A expense included $93 million ($1.21/boe) of impairment expense primarily related to two natural gas producing properties in the Gulf of Mexico. The impairment was caused by disappointing development programs and negative year-end reserve revisions. The carrying values of the impaired properties were reduced to their estimated fair value. In addition, our 2006 DD&A expense included $15 million (2005—$58 million) relating to a partial write down of our purchase price allocation to unproved properties purchased in the North Sea, as a result of unsuccessful exploration activities. Our 2006 average depletion rate excluding impairment charges was $12.38/boe, up 10% from 2005.

In Yemen, we began depleting the permanent production facilities on Block 51 in 2006 following their commissioning earlier in the year. Strong crude oil prices allowed us to continue to maximize recovery of costs we paid on the government's behalf. This increased our corporate average by $0.64/boe.

Our increased Canadian depletion rate reflected depletion of costs for our CBM projects in central Alberta, which increased our corporate average by $0.35/boe. Depletion rates for our deep-water assets in the Gulf of Mexico increased our average by $0.28/boe primarily as a result of reserve revisions late in 2005.

Our depletion rate for our North Sea assets was higher than our average, primarily from the purchase price allocation assigned to them when acquired in 2004. Our corporate average is increasing as the North Sea becomes a larger proportion of our total production and Canada becomes a small portion, following the sale of Canadian conventional oil and gas assets in 2005. This change increased our corporate average by $0.42/boe.

The Stage 3 expansion at Syncrude began producing during the year and we started depleting these assets in 2006. This increased our corporate average by $0.23/boe.

The strong Canadian dollar reduced our corporate DD&A by $0.72/boe from 2005 as the depletion of our international and US assets is denominated in US dollars.

Exploration Expense [1]

(Cdn$ millions)	2007	2006	2005
Seismic	123	128	53
Unsuccessful Drilling	126	169	143
Other	77	65	55
Total Exploration Expense	**326**	**362**	**251**
New Growth Exploration	573	491	456
Geological and Geophysical Costs	123	128	53
Total Exploration Expenditures	**696**	**619**	**509**
Exploration Expense as a % of Exploration Expenditures	47%	58%	49%

Note:

1 2005 includes exploration expense from discontinued operations. See Note 14 to our Consolidated Financial Statements

2007 vs 2006—Lower exploration expense increased net income by $36 million

We invested almost $700 million in exploration oriented activities during the year, primarily related to drilling in the Gulf of Mexico, UK North Sea and CBM in Canada, and acquiring seismic data in the Gulf of Mexico and Norway. In addition, we acquired material land positions in the Gulf of Mexico, and in northeast British Columbia related to an emerging Devonian shale gas play.

Exploration expense decreased $43 million or 25% from last year as a result of fewer unsuccessful exploration wells. In the Gulf of Mexico, we incurred dry hole costs of $59 million as compared to $135 million in 2006; however, this decrease was partially offset by higher unsuccessful well costs in the UK North Sea, Colombia and Canada.

In the deep-water Gulf of Mexico, we drilled a successful appraisal well at Longhorn and evaluated resource estimates. The Longhorn development has been sanctioned and production is expected in 2009. Also in the deep water, our Vicksburg prospect was drilled to a depth of 25,400 feet and encountered hydrocarbons. Core was recovered from the well and studies are underway to assess the potential productivity. Additional drilling in the area is planned in 2008. Our unsuccessful drilling results in the Gulf of Mexico were primarily on the shelf where we expensed $35 million for dry holes. In the deep water, we drilled a sidetrack at Aspen targeting two zones in deeper sands; however, results from the lowest zone were unsuccessful and we expensed $20 million for a portion of the drilling costs of the well.

In the deep-water Gulf of Mexico, we drilled a successful appraisal well at Longhorn. Development has been sanctioned and production is expected in 2009.

In the UK North Sea, we had several exploration successes. We followed up on our successful Golden Eagle well by drilling a sidetrack to appraise the accumulation. We are currently evaluating development options for this discovery. At Selkirk, we successfully completed an appraisal well and sidetrack and are currently assessing development alternatives. At Kildare, we plan to drill an appraisal well in third quarter of 2008. Our 2007 dry hole costs in the UK North Sea were $39 million compared to $21 million in 2006. The $15 million Guinea well was completed in the first quarter; however, the target reservoir was water bearing and the well was abandoned. Further exploration wells at Stag and Dee were plugged and abandoned, resulting in $12 million and $8 million, respectively, in expensed costs.

In Colombia, we expensed $11 million related to the unsuccessful Guaini-1 and Atalea-1 exploratory wells. In Canada, we expensed costs associated with unsuccessful CBM activities at Provost, Kakwa and Sullivan Lake. Seismic data costs of $123 million were comparable with 2006. The Gulf of Mexico and Norway accounted for 74% of the seismic expenditures, as we consider these areas to have significant exploration potential. Data has been acquired during the last two years to support our acreage accumulation efforts.

We plan to invest approximately $600 million in our 2008 exploration and appraisal program and anticipate drilling up to 11 exploration and four appraisal wells in the Gulf of Mexico, North Sea and Yemen.

2006 vs 2005—Higher exploration expense reduced net income by $111 million

Our 2006 exploration activities were focused on drilling 20 wells, mostly in the Gulf of Mexico and the North Sea, and on acquiring seismic data. We were successful at Great White West and Longhorn (formerly Ringo) in the Gulf of Mexico. In early 2007, we completed drilling at our Golden Eagle prospect in the UK North Sea. The discovery well was drilled to approximately 7,500 feet and encountered hydrocarbons.

Our unsuccessful drilling results were primarily in the Gulf of Mexico, where we expensed $135 million in dry hole costs. Early in 2006, we expensed $49 million for the Pathfinder well, which found non-commercial quantities of hydrocarbons, after reaching a total depth of 31,196 feet. Unsuccessful wells on the shelf in the Gulf of Mexico include West Cameron 135 and 109 ($23 million and $14 million respectively) and Vermilion 65 ($15 million). During 2006, we also expensed $29 million of capitalized costs related to Big Bend as it was determined that development was uneconomic and the block was relinquished. In the North Sea, dry hole costs included unsuccessful exploratory wells at Zanzibar ($10 million) and Black Cat ($7 million). Exploration expense also includes costs relating to Ukot South, offshore Nigeria, which encountered wet sands and was plugged and abandoned, and costs relating to three unsuccessful wells on Block 51 in Yemen.

Our geological and geophysical costs include $128 million of seismic data acquired during 2006, half related to the Gulf of Mexico. The balance was spent on acquiring data in Canada, Norway, the North Sea, Nigeria and other international targets.

OIL & GAS AND SYNCRUDE NETBACKS

Netbacks are the cash margins, before general and administrative expenses, we receive for every equivalent barrel sold. The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties. A combination of strong realized prices and new high-margin production from Buzzard increased our cash netback by 32% from 2006 (17% after royalties).

Before Royalties

2007

($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	76.29	40.79	58.16	74.79	71.29	79.76	68.46
Royalties and Other	(34.69)	(7.81)	(7.45)	–	(5.90)	(12.02)	(13.10)
Operating Expenses	(6.56)	(12.91)	(8.43)	(6.94)	(3.45)	(25.80)	(9.45)
In-country Taxes [1]	(9.52)	–	–	–	–	–	(2.69)
Cash Netback	**25.52**	**20.07**	**42.28**	**67.85**	**61.94**	**41.94**	**43.22**

2006

($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Royalties and Other	(32.32)	(7.80)	(7.53)	–	(5.51)	(6.93)	(17.68)
Operating Expenses	(4.45)	(10.31)	(8.17)	(11.28)	(2.87)	(27.53)	(8.77)
In-country Taxes [1]	(8.45)	–	–	–	–	–	(3.72)
Cash Netback	**26.35**	**22.87**	**40.42**	**55.53**	**57.71**	**37.86**	**32.75**

2005

($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Royalties and Other	(28.71)	(8.75)	(8.06)	–	(5.23)	(0.71)	(16.70)
Operating Expenses	(3.63)	(8.21)	(6.35)	(14.90)	(5.55)	(26.95)	(7.36)
In-country Taxes [1]	(7.17)	–	–	–	–	–	(3.34)
Cash Netback	**22.56**	**25.46**	**45.85**	**42.93**	**49.18**	**43.34**	**30.57**

After Royalties

2007

($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	76.29	40.79	58.16	74.79	71.29	79.76	68.46
Operating Expenses	(12.00)	(15.93)	(9.69)	(6.94)	(3.76)	(30.32)	(11.63)
In-country Taxes [1]	(17.42)	–	–	–	–	–	(3.31)
Cash Netback	**46.87**	**24.86**	**48.47**	**67.85**	**67.53**	**49.44**	**53.52**

2006

($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Operating Expenses	(8.11)	(12.73)	(9.45)	(11.28)	(3.13)	(30.43)	(11.96)
In-country Taxes [1]	(15.40)	–	–	–	–	–	(5.07)
Cash Netback	**48.06**	**28.25**	**46.67**	**55.53**	**62.96**	**41.89**	**45.89**

2005

($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Operating Expenses	(6.75)	(10.34)	(7.33)	(14.90)	(6.08)	(27.22)	(10.34)
In-country Taxes [1]	(13.35)	–	–	–	–	–	(4.69)
Cash Netback	**41.97**	**32.08**	**52.93**	**42.93**	**53.88**	**43.78**	**42.94**

Note

1 Comprises income taxes payable in Yemen that are included in the Government's share of profit oil.

ENERGY MARKETING

(Cdn$ millions)	2007	2006	2005
Physical Sales [1]	47,826	40,920	37,873
Physical Purchases [1]	(46,897)	(39,925)	(36,988)
Net Financial Transactions [1]	(49)	314	(38)
Increase in Fair Market Value of Inventory	79	–	–
Net Revenue	959	1,309	847
Transportation Expense	(806)	(789)	(641)
Other	14	20	(2)
Net Marketing Revenue	**167**	**540**	**204**
Contribution to Net Marketing Revenue by Region:			
North America	151	526	186
Asia	11	13	18
Europe	5	1	–
Net Marketing Revenue	**167**	**540**	**204**
Depreciation, Depletion, Amortization and Impairment	(13)	(12)	(11)
General and Administrative	(87)	(112)	(89)
Marketing Contribution to Income from Continuing Operations before Income Taxes	**67**	**416**	**104**
North America			
Natural Gas			
Physical Sales Volumes [2] (bcf/d)	5.8	5.4	4.9
Transportation Capacity (bcf/d)	2.0	3.3	4.0
Storage Capacity (bcf)	39	50	30
Financial Volumes (bcf/d)	21.9	19.8	12.1
Crude Oil			
Physical Sales Volumes [2] (mbbls/d)	655	553	318
Storage Capacity (mbbls)	2,734	1,749	580
Financial Volumes (mbbls/d)	2,134	1,976	819
Power			
Physical Sales Volumes [2] (MW/d)	4,516	4,388	2,548
Generation Capacity (MW/hr)	87	87	53
Asia			
Physical Sales Volumes [2] (mbbls/d)	183	152	192
Financial Volumes (mbbls/d)	256	207	163
Europe			
Financial Volumes (mbbls/d)	529	52	–
Value-at-Risk			
Year End	26	26	24
High	38	33	28
Low	24	17	11
Average	30	23	21

Notes:

1 Marketing's physical sales, physical purchases and net financial transactions are reported net on the Consolidated Statement of Income as marketing and other.

2 Excludes intra-segment transactions.

2007 vs 2006—Reduced energy marketing contribution decreased net income by $373 million

Results from our energy marketing group were below the record year we experienced in 2006 as there were fewer market events to capitalize on, and fundamental changes in commodity markets were difficult to predict with confidence.

As part of our gas marketing strategy, we hold physical transportation and storage capacity contracts that allow us to take advantage of pricing differences between locations (i.e. west vs. east) and time periods (i.e. summer vs. winter). These strategies, particularly time spreads, contributed less to net revenue in 2007 as there were fewer significant weather-related market events (hurricanes or cold winter weather) to capitalize on. These events typically cause time spreads to widen and location spreads to dislocate, presenting trading opportunities for us. In addition, gas prices were supported throughout the year by high oil prices despite record gas storage levels. We were successful at generating revenue through the day-to-day optimization of our transportation and storage capacity, as well as our fee-for-service asset management activities.

The contribution of our North American crude oil marketing team was lower than 2006 as their portfolio, both physical and financial, was positioned to take advantage of contango (rising forward month prices) in the crude oil forward curve. Late summer, near-term crude oil prices moved up sharply, moving the forward curve from contango to backwardation (falling forward month prices). As a result, we suffered losses in our financial time spread positions. We continued to capture profits from location and quality spreads by diverting crude oil to more attractive markets or blending to enhance crude quality.

Our power marketing group remains the largest supplier of power to the commercial and industrial sector in Alberta and continued to deliver solid returns.

Our 2007 results include fair value gains of $79 million on our natural gas and crude oil in storage and pipelines in the fourth quarter. New inventory standards under Canadian GAAP require us to carry our trading commodity inventories at fair value, rather than at cost as was previously the case. We adopted these new rules in the fourth quarter.

In late 2006, we de-designated certain futures contracts that were designated as cash flow hedges of future sales of our natural gas in storage. These contracts were de-designated since it became uncertain that the future sales would occur within the designated time frame. As it was reasonably possible that the future sales could have taken place as designated at the inception of the hedging relationship, gains of $65 million on the futures contracts were deferred in accounts payable at December 31, 2006. These gains were recognized in marketing and other income during the first quarter of 2007.

Results from our marketing group vary between periods and historical results are not necessarily indicative of future results. Marketing results depend on a variety of factors such as market volatility, changes in time and location spreads, the manner in which we use our storage and transportation assets and the change in value of the financial instruments we use to hedge these assets.

2006 vs 2005—Net marketing revenue increased net income by $336 million

Marketing had record results in 2006, with all areas achieving records. The largest contribution came from our North American natural gas marketing group where we capitalized on our asset-based trading strategy. Time and location spread trading generated most of our gas gains but we were also successful in generating revenues through the optimization of our transportation and storage capacity. Volatility within the North American gas markets created market opportunities for us to capitalize on. North American gas prices started 2006 at US$10.63/mcf and closed the year at US$6.30/mcf. Storage overhang and speculation around weather and possible hurricanes caused significant changes in prices during the year. We also took advantage of opportunities late in the year to add to our storage capacity.

Our crude oil marketing group also generated record results by successfully taking advantage of crude quality, location and time spreads. The group generated physical and financial trading gains by taking advantage of the contango (rising forward month prices) in the crude oil forward curve. In addition, we captured profits around quality spreads by diverting crude oil, or by blending to enhance the crude quality, and attract higher prices. While our strategies were consistent with prior years, we executed more transactions and added more capacity, particularly storage, during the year.

Our power marketing group became the largest supplier of power to the commercial and industrial sector in Alberta and net revenue contributions exceeded expectations.

We continued our expansion into new markets during 2006 with acquisitions in the North American NGL trading business and a UK acquisition which positioned us in the UK and European gas and power markets.

Composition of Net Marketing Revenue

(Cdn$ millions)	2007	2006	2005
Trading Activities (Physical and Financial)	147	520	195
Non-Trading Activities	20	20	9
Total Net Marketing Revenue	**167**	**540**	**204**

Trading Activities

In our energy marketing group, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts not designated as hedges for accounting purposes using mark-to-market accounting and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is included with accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

We value derivative trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes. We do not value any derivative contracts using internal models.

Fair Value of Derivative Contracts

At December 31, 2007, the fair value of our derivative contracts totalled $6 million (2006—$360 million). Below is a breakdown of this fair value by valuation method and contract maturity.

	Maturity				
(Cdn$ millions)	< 1 year	1-3 years	4-5 years	> 5 years	Total
Prices					
Actively Quoted Markets	(204)	96	(21)	(8)	(137)
From Other External Sources	125	9	7	2	143
Based on Models and Other Valuation Methods	–	–	–	–	–
Total	**(79)**	**105**	**(14)**	**(6)**	**6**

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	Total
Fair Value at December 31, 2006	**360**
Change in Fair Value of Contracts	(10)
Net Losses (Gains) on Contracts Closed	(344)
Changes in Valuation Techniques and Assumptions [1]	–
Fair Value at December 31, 2007	**6**

Note:

1 Our valuation methodology has been applied consistently year-over-year.

The fair values of our derivative contracts will be realized over time as the contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. The average term of our derivative contracts is approximately 1.4 years. Those maturing beyond one year primarily relate to North American natural gas positions.

Fair Value of Trading Inventories and Capacity Contracts

As part of our gas marketing strategy, we hold physical transportation and storage capacity contracts that allow us to take advantage of pricing differences between locations (i.e. west vs. east) and time periods (i.e. summer vs. winter). These capacity contracts have market value, similar to financial commodity contracts, as future margins realized depend on future prices and, more importantly, pricing differences. The market value of these capacity contracts varies depending on the change in future prices and pricing relationships. We routinely hedge the economic value of our capacity contracts using various types of derivative contracts, thereby reducing volatility in our economic results. Accounting rules

can increase volatility in our reported results since they require us to recognize the change in fair value of derivative contracts hedging our capacity contracts, but do not allow us to recognize the change in fair value of the capacity contracts themselves until the contracts are used. As a result, when prices or pricing relationships change, we may be required to include gains or losses in our reported results in different periods even though our underlying economic results may be largely unchanged.

Similar to capacity contracts, we hold commodity inventories for trading purposes that allow us to take advantage of pricing differences between time periods (i.e. summer vs winter). We carry these inventories at fair value as measured by the one-month forward price, less any costs to sell. We economically hedge the future value of our trading inventories based on our expected holding period, which is generally more than one month. The derivative contracts used to hedge our trading inventories are carried at fair value, which considers the future settlement of the contract, whereas the commodity inventories are valued only one-month forward. The timing difference can create volatility in our reported results.

At the end of 2007, the unrecognized future value of the commodity inventory and capacity contracts was a gain of $51 million (2006—$81 million loss). The future commitment for these capacity contracts has been included in our contractual obligations, commitments and guarantees in the MD&A.

CHEMICALS

(Cdn$ millions)	2007	2006	2005
Net Sales	414	407	398
Sales Volumes (thousand short tons)			
Sodium Chlorate	478	487	493
Chlor-alkali	465	451	450
Operating Profit [1, 3]	151	124	136
Operating Margin [2, 3]	36%	30%	34%
Chemicals Contribution to Income from Continuing Operations Before Income Taxes	64	44	37
Capacity Utilization	94%	95%	96%

Notes:

1 Total revenues less operating costs, transportation and other.

2 Operating profit divided by net sales.

3 Includes foreign exchange gains or losses on debt.

2007 vs 2006—Higher chemicals operating profit increased net income by $27 million

Our investment in the chemicals business is held through our 61.4% interest in the Canexus Limited Partnership. The remaining interest is publicly traded through the Canexus Income Fund. Realized North America chlorate prices were up 5% in 2007 and sales volumes remained strong, despite unplanned maintenance of our facilities and pulp mill shut downs. The full effect of the price increase was partially eroded by the strengthening Canadian dollar which reduced US-dollar denominated sales by $9 million. Brazilian sales remained strong with continued demand from our main pulp mill customer Aracruz Cellulose.

The expansion at our plant in Brandon, Manitoba is well underway. Completion is expected in 2008 with capacity expected to increase 12%. The Brandon plant benefits from low electricity rates in Manitoba where the electricity market is based on hydroelectric power and is regulated. We also benefit from the economies of scale we achieve as this is the world's largest sodium chlorate facility.

Operating profit includes foreign exchange gains of $30 million, primarily from unrealized gains on revaluation of long-term debt.

2006 vs 2005—Lower chemicals operating profit decreased net income by $12 million

While North American prices for sodium chlorate remained strong throughout 2006, sales volumes fell slightly from 2005 as a result of pulp mill closures. Chlor-alkali volumes and prices in North America remained steady. US-dollar denominated North American sales were reduced $12 million from the stronger Canadian dollar during 2006. Sales and operations from the Brazil plant remained solid as a result of strong demand from Aracruz Cellulose, our primary customer, and from the merchant market.

CORPORATE EXPENSES

General and Administrative (G&A)

(Cdn$ millions)	2007	2006	2005
General and Administrative Expense before Stock-Based Compensation	336	345	302
Stock-Based Compensation [1]	38	210	507
Total General and Administrative Expense	**374**	**555**	**809**

Note:

1 Includes cash and non-cash expenses related to our tandem option plan and stock appreciation rights plan.

2007 vs 2006—Lower costs increased net income by $181 million

G&A expense dropped 33% from 2006 with lower stock-based compensation expense. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation expense and related obligations. At the end of 2007, our stock price closed unchanged from the end of 2006. As a result, most of our 2007 stock-based compensation expense is related to vesting of stock-based compensation plans. Cash payments to employees for stock-based compensation programs increased 24% from 2006 to $147 million.

During the year, we incurred additional employee costs as we continue to expand oil and gas operations internationally and marketing operations in Europe and North America. This was offset by lower variable compensation on oil and gas and marketing operations.

2006 vs 2005—Lower costs increased net income by $254 million

Our 2006 G&A expense before stock-based compensation increased 14% primarily from additional costs to expand our marketing operations into new markets. Acquisitions during 2006 allowed us to increase our North American NGL business and to expand our European trading operations. Our G&A expense also included higher variable compensation stemming from our marketing group's strong performance in 2006.

In 2006, our share price increased 16%, creating over $2.3 billion of shareholder value. The stock based compensation expense represented approximately 9% of the increase in shareholder value. Cash payments to employees for our stock-based compensation programs were $119 million in 2006, up 61% from 2005.

Interest

(Cdn$ millions)	2007	2006	2005
Interest	341	294	275
Less: Capitalized	(173)	(241)	(178)
Net Interest Expense	**168**	**53**	**97**
Effective Rate	6.2%	6.3%	6.4%

2007 vs 2006—Higher net interest expense decreased net income by $115 million

Financing costs increased $47 million from 2006. Additional borrowings to finance our 2007 capital program increased interest costs by approximately $69 million. This was partially offset by the stronger Canadian dollar which reduced our US-dollar denominated interest by $22 million.

Interest capitalized on our major development projects was lower by $68 million from 2006. We stopped capitalizing interest on the Syncrude Stage 3 expansion and Buzzard in 2007 as these projects were brought on stream. We expect to continue capitalizing interest on Long Lake and Ettrick until their planned completion in 2008. After that, we expect net interest expense to increase.

2006 vs 2005—Lower net interest expense increased net income by $44 million

Our 2006 financing costs increased $19 million from 2005. Additional borrowings to finance our 2006 capital program increased financing costs by approximately $28 million. This was partially offset by the stronger Canadian dollar which decreased our US-dollar denominated interest by $16 million. The Canexus debt, consolidated with our results, increased our interest expense by $7 million.

The amount of interest we capitalized on our major development projects grew by $63 million, primarily from increased investment in Buzzard, Long Lake and Syncrude's Stage 3 expansion prior to its start-up.

Income Taxes

(Cdn$ millions)	2007	2006	2005
Current	434	368	339
Future	358	315	(234)
Total Provision for Income Taxes	**792**	**683**	**105**
Disclosed as:			
Provision for Income Taxes—Continuing Operations	792	683	234
Provision for Income Taxes—Discontinued Operations [1]	–	–	(129)
Total Provision for Income Taxes	**792**	**683**	**105**
Effective Rate	42%	53%	8%

Note
1 See Note 14 to our Consolidated Financial Statements.

2007 vs 2006—Effective tax rate decreases from 53% to 42%

Our 2007 effective tax rate was lower than 2006, as we recorded additional tax expense in 2006 due to a UK tax rate increase. Excluding the impact of this rate increase, our effective tax rate in 2006 would have been 33%. The 2007 increase is due to a higher proportion of earnings from the UK where the corporate income tax rate on oil and gas activities is 50%. Current income taxes include cash taxes in Yemen, the UK, Colombia and the US.

2006 vs 2005—Effective tax rate increases from 8% to 53%

Effective January 1, 2006, the UK government increased the supplementary tax rate on our North Sea oil and gas activities from 10% to 20%, increasing the combined rate to 50%. This increased our future income tax liabilities, resulting in a charge of $277 million during the first quarter of 2006. Federal and certain provincial governments in Canada also reduced corporate income tax rates in 2006, which lowered our future income tax liabilities by $32 million. Our effective tax rate excluding the impact of these tax rate changes was 33%. Our current income tax provision included cash taxes in Yemen, the US, Colombia and Canada.

Other

(Cdn$ millions)	2007	2006	2005
Decrease in Fair Value of Crude Oil Put Options	(43)	(11)	(196)
Block 51 Settlement	–	(151)	–
Business Interruption Insurance Proceeds	–	154	2
Gain on Dilution of Interest in Chemicals Business	–	–	193
Gain on Disposition of Oil and Gas Assets included as Discontinued Operations	–	–	225

During 2007, we purchased put options on 36 million barrels of our 2008 crude oil production. These options establish a Dated Brent floor price of US$50/bbl on these volumes, are settled annually and provide downside price protection without limiting our upside to higher prices. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. The put options were purchased for $24 million; however, strong crude oil prices reduced the fair value of these options to nil, and we recorded a loss of $24 million during the year.

During 2006, we purchased put options on approximately 105,000 bbls/d of our 2007 crude oil production for $26 million. These options established a WTI floor price of US$50/bbl on these volumes. During 2006, an increase in the forward WTI prices lowered the fair value of the options and we recognized a loss of $7 million for the year ended December 31, 2006. Strengthening WTI in 2007 reduced the market value of the options to nil, creating a loss of $19 million in 2007.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2005 and 2006. These options created an average floor price for this production of US$43.17/bbl in 2005 and US$38.17/bbl in 2006. During 2005, a significant increase in forward crude prices reduced the value of these options by $196 million. Strong WTI prices in 2006 reduced the market value of these remaining options to nil, causing us to expense $4 million in 2006.

In 2006, a court of arbitration concluded that we breached an Area of Mutual Interest agreement with Occidental Petroleum Corporation (Occidental). As a result, Occidental was entitled to monetary damages. In late 2006, we settled the arbitration by agreeing to pay Occidental US$135 million ($151 million) as monetary damages. This amount was paid in the first quarter of 2007.

In 2006, we received $154 million of business interruption insurance proceeds related to 2005 production losses caused by Gulf of Mexico hurricanes and by generator failures in our UK operations.

As a result of the sale of our chemicals business to the Canexus Limited Partnership in 2005, we recorded a gain on the dilution of our interest from 100% to 61.4% of $193 million. Our gain on the 2005 sale of Canadian oil and gas properties in Alberta, British Columbia and Saskatchewan was $225 million.

OUTLOOK FOR 2008

In 2008, we plan to invest $2.4 billion in capital activities as follows:

- 29% in development projects to bring Long Lake Phase 1 and Ettrick in the North Sea on stream in 2008, and progress Longhorn in the Gulf of Mexico and CBM at Fort Assiniboine in Alberta;
- 17% on early-stage development projects expected to contribute production and cash flow growth beyond 2008. These include additional phases of oil sands in the Athabasca region, Usan offshore Nigeria, and our Knotty Head and Golden Eagle discoveries in the Gulf of Mexico and North Sea, respectively;
- 25% on exploration primarily in our North Sea and Gulf of Mexico growth areas; and
- 29% to exploit potential in our existing producing assets and in other corporate assets.

Details of our 2008 capital program are included in the Capital Investment section of the MD&A.

Daily Production

In 2008 we expect additional production growth over 2007 and expect production to range between 220,000 and 240,000 boe/d (260,000 and 280,000 boe/d before royalties). In 2008, we expect to see the impact of a full year of Buzzard production and first oil from Ettrick in mid 2008. We are steaming the reservoir at Long Lake and expect bitumen production to ramp up in the spring, prior to upgrader start up mid 2008.

2008 Estimated Production

	2008 Estimated Production		2007 Production	
(mboe/d)	Before Royalties	After Royalties	Before Royalties	After Royalties
United States	25 – 30	20 – 25	33	29
United Kingdom	95 – 115	95 – 115	84	84
Yemen	50 – 55	27 – 32	72	40
Canada	45 – 50	40 – 45	37	30
Syncrude	20 – 25	17 – 22	22	19
Other International	6 – 7	5 – 6	6	5
Total	**260 – 280**	**220 – 240**	**254**	**207**

Cash Flow and Sensitivities

We expect to generate approximately $2.9 billion in cash flow from operating activities in 2008, after cash taxes of approximately $1 billion, assuming the following:

WTI (US$/bbl)	70.00
NYMEX Natural Gas (US$/mmbtu)	6.75
Oil & Gas and Syncrude Operating Costs (Cdn$/boe)	10.00
US to Canadian Dollar Exchange Rate	0.97

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities, after cash taxes, as follows:

(Cdn$ millions)	
WTI—US$1/bbl change above US$50	39
WTI—US$1/bbl change below US$50	22
NYMEX Natural Gas—US $0.50/mcf change	24
Exchange Rate—$0.01 US/Cdn change	28

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	2007	2006
Net Debt [1]		
Bank Debt	413	1,410
Public Senior Notes	3,758	2,885
Total Senior Debt	4,171	4,295
Subordinated Debt	439	536
Total Debt	4,610	4,831
Less: Cash and Cash Equivalents	(206)	(101)
Total Net Debt	**4,404**	**4,730**
Shareholders' Equity [2]	**5,610**	**4,636**

Notes:

1 *Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents*

2 *At January 31, 2008, there were 528,502,991 common shares and US$460 million of unsecured subordinated securities outstanding. After November 8, 2008, we have the option to redeem these subordinated securities by issuing common shares. The number of shares issuable depends on the common share price on the redemption date.*

Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows and capital investment. We ended the year with net debt of $4.4 billion, $326 million lower than 2006. The decrease was primarily caused by the strengthening Canadian dollar relative to the US-dollar which reduced our US-dollar denominated debt by over $700 million. The impact of foreign exchange was partially offset as our capital investment exceeded cash flow from operating activities by over $500 million. This shortfall was financed with long-term debt.

In May 2007, we issued US$250 million of 10-year senior notes and US$1,250 million of 30-year senior notes and used the proceeds to repay amounts outstanding under term credit facilities. Issuing this debt extended the average term-to-maturity of our debt to 21 years. Approximately 7% of our long-term debt is repayable within the next three years.

The year-over-year change in our net debt results from:

(Cdn$ millions)	2007	2006
Capital Investment	3,401	3,408
Cash Flow from Operating Activities	(2,830)	(2,374)
Excess of Capital Investment over Cash Flow	571	1,034
Dividends on Common Shares	53	52
Issue of Common Shares	(56)	(48)
Foreign Exchange Translation of US-dollar Debt and Cash	(745)	31
Net Proceeds on Disposition of Assets	(4)	(27)
Other	(145)	49
Increase (Decrease) in Net Debt	**(326)**	**1,091**

The change in our net debt has improved our 2007 leverage as reflected in the following ratios:

(times)	2007	2006	2005
Net Debt to Cash Flow from Operating Activities	1.6	2.0	1.7
Interest Coverage [1]	12.1	9.6	9.7

Note

1 *Earnings before interest, taxes, DD&A and exploration expense divided by interest expense (before capitalized interest).*

Our business strategy is focused on value-based growth through full-cycle exploration and development of conventional and unconventional resources, supplemented by strategic acquisitions when appropriate. Since most of our projects have long-cycle times, requiring significant amounts of capital prior to cash flow generation, we have successfully leveraged our balance sheet many times in the past, including to:

- develop the Masila project in Yemen in 1993;
- acquire Wascana in 1997;
- repurchase 20 million common shares in 2000;
- acquire the remaining interest in Aspen in 2003;
- acquire the Buzzard project and other key assets in the North Sea in 2004; and
- construct the first phase of Long Lake.

Each time, we exceeded our internal net debt to cash flow target band; however, we successfully brought our leverage down through asset sales and incremental cash flows. In 2006, we again increased our leverage investing in major development projects at Buzzard and Long Lake. With new cash flow from Buzzard in 2007, we reduced our ratio of net debt to cash flow from operating activities.

Change in Working Capital

(Cdn$ millions)	2007	2006	Increase/ (Decrease)
Cash and Cash Equivalents	206	101	105
Restricted Cash and Margin Deposits	203	197	6
Accounts Receivable	3,502	2,951	551
Inventories and Supplies	659	786	(127)
Future Income Tax Assets	18	479	(461)
Accounts Payable and Accrued Liabilities	(4,180)	(3,879)	(301)
Other	4	(1)	5
Total	**412**	**634**	**(222)**

Increased production rates and stronger commodity prices contributed to higher accounts receivable. Our marketing group reduced the amount of natural gas in storage at the end of 2007; however, this was partially offset by slightly higher crude oil inventories. New accounting rules require that the commodity inventory held by our energy marketing group be carried at fair value. These new rules also require us to reclassify $51 million of critical spare parts for our oil and gas activities from inventories and supplies to property, plant and equipment. The current portion of future income tax assets decreased from 2006 as strong Buzzard production contributed to utilizing available tax losses in the UK. Stronger crude oil prices also increased accrued liabilities for our marketing operation. This increase was partially offset by lower stock-based compensation accruals.

The strengthening Canadian dollar relative to the US dollar impacted our US-dollar denominated working capital by reducing accounts receivable, inventories and accounts payable by approximately $275 million, $75 million and $250 million, respectively.

Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual in any year for capital expenditures to exceed our cash flow. In addition, we require liquidity for our energy marketing business. Accordingly, we maintain significant committed credit facilities. At December 31, 2007, we had unsecured term credit facilities of US$3 billion that are available until 2012. At year end, $211 million was drawn on these facilities and $283 million of these facilities was utilized to support letters of credit. We also had $665 million of uncommitted, unsecured credit facilities, of which $196 million was supporting letters of credit at December 31, 2007.

From time to time, we access capital markets to meet our financing needs. We also use various financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI put options to mitigate cash flow volatility. Overall, we manage our capital structure to maintain flexibility so we can fund our capital programs throughout highs and lows of the price cycles inherent in the oil and gas business.

The following table shows how we finance our business activities. When our operating cash flows exceed our investment requirements, we generally pay down debt. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn$ millions)	2007	2006	2005	2004	2003
Cash Flow from Operating Activities	2,830	2,374	2,143	1,606	1,405
Cash Flow from Investing Activities	(3,281)	(3,388)	(1,864)	(4,013)	(1,219)
Surplus (Deficiency)	(451)	(1,014)	279	(2,407)	186
Cash Flow from Financing Activities	677	1,081	(274)	1,426	1,006
	226	**67**	**5**	**(981)**	**1,192**

In late 2003, we pre-funded debt repayments by raising more than $1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher-cost debt, and coupled with acquisition credit facilities, acquired the North Sea assets. In 2005, we used cash flow and proceeds from asset dispositions to fund our capital program and repay debt. In 2006, we borrowed approximately $1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US$1.5 billion in senior debt to repay outstanding term credit facilities and $150 million in medium term notes, and to partially fund our 2007 capital program.

Our marketing business also requires liquidity to support its asset-based trading strategy. We require liquidity for working capital, cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements typically require collateral be posted if adverse credit-related events, such as reduced credit ratings, occur. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

Future Liquidity

Our future liquidity depends primarily on cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Assuming WTI of US$70/bbl, we expect our 2008 cash flow to exceed capital and dividend requirements by approximately $400 million. In July 2008, we will repay $125 million of medium term notes that become due with funds from our term credit facilities.

In 2008, we expect cash flow of approximately $2.9 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US$/bbl)	70.00
NYMEX Natural Gas (US$/mmbtu)	6.75
US to Canadian Dollar Exchange Rate	0.97

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2008 section on page 62 to see how changes in the above assumptions can impact our cash flow.

A number of our development projects require capital to bring them on stream. In 2008, we expect to invest $400 million to bring Long Lake Phase 1 on stream, $165 million to progress our Usan development offshore Nigeria, and $200 million to bring Ettrick in the North Sea on stream. While these development projects lack exploration risk, they are subject to other risks including higher than anticipated capital costs or delayed start-up. We maintain undrawn committed credit facilities to manage this risk. We also have a US$2.5 billion shelf prospectus available in the US and Canada.

At December 31, 2007, the average term-to-maturity of our long-term debt was 21 years.

(Cdn$ millions)	2008	2009	2010	2011	2012
Term Credit Facilities [1]	–	–	–	–	211
Canexus LP Term Credit Facilities	–	–	202	–	–
Medium Term Notes	125	–	–	–	–
Total	**125**	**–**	**202**	**–**	**211**

Note:

1 $3.0 billion available until 2012.

With our expected cash flow streams, commodity price and hedging strategies, current liquidity levels, and access to debt and equity markets, we expect to be able to fund all planned capital, dividends and debt repayments, and meet other obligations that may arise from our oil and gas, Syncrude, chemicals and energy marketing operations.

In the last four years, we declared common share dividends of $0.10 per share each year.

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

		Payments			
(Cdn$ millions)	**Total**	**<1 year**	**1-3 years**	**4-5 years**	**>5 years**
Short-Term and Long-Term Debt	4,688	125	202	211	4,150
Interest on Long-Term Debt [1]	6,395	268	527	527	5,073
Operating Leases [2]	610	76	201	176	157
Capital Leases	117	5	10	10	92
Energy Commodity Contract Liabilities	576	413	135	25	3
Transportation and Storage Commitments [2]	922	368	271	151	132
Work Commitments and Purchase Obligations [3]	2,137	966	575	522	74
Asset Retirement Obligations	2,165	40	58	39	2,028
Total	**17,610**	**2,261**	**1,979**	**1,661**	**11,709**

Notes:

1 Excludes interest on variable rate debt.

2 Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.

3 Some of these payments relate to work commitments that we can cancel without penalties or additional fees.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur.

- Short-term and long-term debt amounts are included on our December 31, 2007 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allows our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to future production at Long Lake.
- Energy commodity contract liabilities include the purchase and sale of physical quantities of oil and natural gas, and financial derivatives used to manage our exposure to commodity prices. For contracts where the price is based on an index, the amount is based on forward market prices at December 31, 2007. For certain contracts, we may net settle. These contracts are included in our Consolidated Balance Sheet at fair value.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and includes Long Lake ($192 million) and Ettrick in the North Sea ($139 million). Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates. The remainder of our 2008 capital investment is discretionary.
- We have included $821 million in work commitments for drilling rigs we have contracted in the North Sea and Gulf of Mexico, over the next five years.
- We have $2,165 million of undiscounted asset retirement obligations after inflation. As of December 31, 2007, the discounted value ($832 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including $40 million of current liabilities). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.

- We have unfunded obligations under our defined benefit pension plans of $130 million (Nexen—$72 million; Canexus—$7 million; Syncrude—$51 million). Our obligations for Nexen and Canexus include $63 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are not determinable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2008.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when future payments would be required.

From time to time, we enter into contracts that require us to indemnify parties against possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe existing indemnifications would not have a material adverse effect on our liquidity, financial condition or results of operations.

Credit Ratings

Currently, our senior debt is rated Baa2 by Moody's Investor Service, Inc. (Moody's), BBB by Dominion Bond Rating Service (DBRS) and BBB- by Standard & Poor's (S&P). In addition, Moody's and DBRS currently rate our outlook as stable while S&P has a positive outlook. Our strong financial results, ample liquidity and financial flexibility continue to support our credit ratings.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event, such as a drop in credit ratings, occurs. Based on contracts in place and commodity prices at December 31, 2007, we could be required to post collateral of up to $1.2 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Just as we may be required to post collateral if we were downgraded below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us if they are downgraded to non-investment grade.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees on page 66 and in Note 15 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2007, we had outstanding letters of credit supported by $283 million of unsecured term credit facilities and $196 million of uncommitted unsecured credit facilities.

Contingencies

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 15 to the Consolidated Financial Statements, which is incorporated here by reference for a discussion of our contingencies.

CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect: 1) the reported amounts of our assets and liabilities; 2) the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements; and 3) our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, derivative contract assets and liabilities and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

Oil and Gas Accounting—Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties.

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

Reserve estimates for each property are internally prepared at least annually by the property's reservoir engineer. They are reviewed by engineers familiar with the property and by divisional management. An Executive Reserves Committee, including our CEO, CFO and board-appointed internal qualified reserves evaluator, meet with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator assesses whether our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included in an exhibit to this Form 10-K.

Our reserves are based on internal estimates. To increase our confidence in our estimates, we have at least 80% of our oil and gas and Syncrude reserves either evaluated or audited annually by independent qualified reserves consultants. Given that reserve estimates are based on numerous assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio often differ by significantly more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest.

The nature and extent of the independent evaluations and audits, and the results thereof, are provided in the section on Reserves, Production and Related Information on page 16.

The board of directors has a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas and Syncrude reserves and disclosures of reserves data and related oil and gas and mining activities. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with each of the internal qualified reserves evaluator and independent reserves

consultants, independent of management, to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

The Reserves Committee has reviewed our procedures for preparing the reserves estimates and related disclosures. It has reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result, the Reserves Committee is satisfied that the internally-estimated reserves are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the board has approved the reserves estimates and related disclosures in the Form 10-K.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2007, $126 million of our total $360 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by $150 million, net of income tax.
- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2007, oil and gas depletion of $1,213 million was recorded in depletion, depreciation, amortization and impairment expense. If our reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $121 million, assuming no other changes to our reserves profiles.
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

Impairments

Property, Plant and Equipment

We evaluate our long-lived assets (oil and gas properties, Syncrude and chemicals) for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant negative revision to our reserves estimates, changes in operating and capital costs, or significant or adverse political changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flow for a property is less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value.

Cash flow estimates for our impairment assessments require assumptions about two primary elements—future prices and reserves. Our estimates of future prices require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US$25.24/bbl to US$99.62/bbl and US$4.20/mmbtu to US$15.38/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows are generally based on our assumptions of long-term prices and operating and development costs. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in these estimates would impact all businesses with the exception of chemicals and energy marketing.

It is difficult to determine and assess how a decrease in proved reserves impacts our impairment tests. The relationship between the reserves estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserves estimate decrease would have on our assessment of impairment.

Goodwill

We test goodwill for impairment annually based on estimated future cash flows of the reporting unit to which the goodwill is attributable. In addition, we test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount. If our goodwill is impaired, we write it down to its implied fair

value, based on the fair value of the assets and liabilities of the underlying reporting unit. The process of assessing goodwill for impairment necessarily requires us to determine the fair values of our assets and liabilities, and involves making various assumptions and judgments.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years into the future. Also, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries where we operate.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the future value of the estimated retirement obligations associated with our oil and gas wells and facilities, Syncrude assets and chemical plants. In arriving at amounts recorded, numerous assumptions and judgments are made on ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations we record increase the carrying cost of our property, plant and equipment and accretes with the passage of time. A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our net income.

It is difficult to determine what impact a change in any of our assumptions would have on our financial results. As a result, we are unable to provide a reasonable sensitivity analysis on changes in our assumptions.

Business Combination—Purchase Price Allocation

We account for business acquisitions using the purchase method of accounting. Under this method, we are required to record on our Consolidated Balance Sheet the estimated fair values of the acquired company's assets and liabilities at the acquisition date. The excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill.

We make various assumptions and judgments in determining the fair values of the acquired company's assets and liabilities, the most significant of which are in estimating the fair value of the oil and gas properties. To determine the fair value of these properties, we estimate (a) oil and gas reserves using our reserve standards, (b) additional reserves potential and (c) future prices of oil and gas.

Our reserve estimates are based on work performed by our engineers and outside consultants. Judgements associated with these estimated reserves are described earlier in our critical accounting estimates discussion entitled "Oil and Gas Accounting—Reserves Determination". Our estimates of future prices are based on prices derived from a consensus of future price forecasts among industry analysts and our own assumptions. The judgments associated with these estimates are described earlier in our critical accounting estimates discussion entitled "Impairments—Property, Plant and Equipment".

We apply our estimated future prices to the estimated reserves quantities acquired, and we estimate future operating and development costs to arrive at estimated future net revenues for the properties acquired. For proved properties, we discount the future net revenues using after-tax discount rates. The same principles are applied in arriving at the fair value of unproved properties acquired. These unproved properties generally represent the value of the probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, an appropriate risk-weighting factor is applied to the discounted future net revenues of the probable and possible reserves in each particular instance.

Future Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and tax purposes. We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have adequately provided for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In December 2006, the Canadian Accounting Standards Board (AcSB) issued two new Sections relating to financial instruments: Section 3862, *Financial Instruments—Disclosures*, and Section 3863, *Financial Instruments—Presentation*. Both sections are effective for annual and interim periods beginning on or after October 1, 2007 and require increased disclosure of financial instruments.

In December 2006, the AcSB issued Section 1535, Capital Disclosures, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital. The standard is effective for annual periods beginning on or after October 1, 2007 and will require additional disclosure.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized as assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We are currently evaluating the impact these sections will have on our results of operations or financial position.

In January 2006, the AcSB adopted a strategic plan for the direction of accounting standards in Canada. Accounting standards for public companies in Canada are expected to converge with the International Financial Reporting Standards by 2011. The timing for convergence has not been confirmed by the AcSB. We continue to monitor and assess the impact of these convergence efforts.

US Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement 157, *Fair Value Measurements*. Statement 157 defines fair value, establishes a framework for measuring fair value under US generally accepted accounting principles and expands disclosures about fair value measurements. For fiscal years beginning after November 15, 2007, companies must implement the standard for financial assets and liabilities, as well as for any other assets and liabilities carried at fair value on a recurring basis in financial statements. However, a one year deferral for the implementation of Statement 157 is provided for other non financial assets and liabilities. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

Effective December 31, 2006, we adopted the recognition and disclosure provisions of FASB Statement 158, *Employers' Accounting for Defined Benefit Pension And Other Postretirement Plans*. This statement also requires we measure the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. We do not expect the adoption of the change in measurement date in 2008 to materially impact our results of operations or financial position.

In February 2007, FASB issued Statement 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. The statement allows for the elective measurement of eligible financial instruments and certain other items at fair value in order to mitigate volatility in reported earnings without having to apply complex and detailed hedge accounting rules. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2007, FASB issued Statement 141(revised), *Business Combinations*. Statement 141(revised) establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Noncontrolling Interests in Consolidated Financial Statements*, an amendment of ARB. No 51. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to normal market risks inherent in the oil and gas, Syncrude, energy marketing and chemicals businesses, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

NON-TRADING

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for exploration and development.

Our crude oil prices are based on various reference prices, primarily WTI and Brent crude oil reference prices and other prices which generally track the movement in WTI and Brent. Adjustments are made to the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and supply and demand fundamentals, and to a lesser extent local market conditions.

In 2007, WTI averaged US$72.31/bbl, reaching a high of US$99.29/bbl and a low of US$49.90/bbl. Dated Brent, on which approximately 80% of our production is priced, averaged $72.52/bbl, reaching a high of US$96.02/bbl and a low of US$50.68/bbl. NYMEX natural gas prices averaged US$7.12/mmbtu in 2007, reaching a high of US$8.71/mmbtu and a low of US$5.19/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2008 cash flow from operating activities and net income are as follows:

(Cdn$ millions)	Cash Flow	Net Income
WTI—US$1/bbl change above US$50	39	36
WTI—US$1/bbl change below US$50	22	20
NYMEX Natural Gas—US$0.50/mcf change	24	20

These sensitivities are based on our estimated 2008 oil and gas production and assume a Canadian/US dollar exchange rate of $0.97. Our estimated oil and gas production range for 2008 is between 260,000 and 280,000 boe/d before royalties, of which approximately 16% is gas.

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In 2007, we purchased Dated Brent put options to manage the commodity price risk exposure on a portion of our oil production in 2008, by establishing an annual average Dated Brent floor price of US$50/bbl on 36 million barrels or about 100,000 bbls/d of production.

Foreign Currency Risk

A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations; and
- short-term and long-term borrowings.

The Canadian/US dollar exchange rate averaged $0.93 in 2007, ranging from a low of $0.84 to a high of $1.09.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2008 cash flow from operating activities, net income, capital expenditures and long-term debt is as follows:

(Cdn$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-term Debt
$0.01 Change in US to Cdn	28	17	15	44

Our sensitivities to changes in the Canadian/US dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar denominated long-term debt for 2008. These estimates are based on a WTI price for crude oil of US$70/bbl, a NYMEX natural gas price of US$6.75/mmbtu, operating costs of $10/boe and a Canadian/US dollar exchange rate of $0.97.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations.

Our chemicals operations are exposed to changes in the US-dollar exchange rate as part of their sales are denominated in US-dollars. Canexus periodically purchases US-dollar call options to reduce this exposure. Under outstanding option contracts at December 31, 2007, Canexus had the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.95 to February 29, 2008.

We do not have any material exposure to highly inflationary foreign currencies.

Interest Rate Risk

We are exposed to fluctuations in interest rates on our floating-rate debt. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2008 cash flow from operating activities and net income is as follows:

(Cdn$ millions)	Cash Flow	Net Income
Interest Rates—1% change in rates	5	3

Our sensitivity to changes in interest rates is based on 2008 estimated average floating rate debt of $475 million and a Canadian/US dollar exchange rate of $0.97.

Our floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2007, fixed-rate borrowings comprised 91% (2006—73%) of our long-term debt at an effective average rate of 6.3% (2006—6.3%). During the year, we periodically borrow under our committed, unsecured, term credit facilities and at December 31, 2007, floating-rate debt comprised 9% (2006—27%) of our long-term debt at an effective average rate of 5.8% (2006—5.7%) ranging from a low of 4.2% to a high of 8.75% during 2007.

We had no interest rate swaps outstanding in 2007 or 2006.

TRADING

Commodity Price Risk

Our marketing group markets and trades crude oil, natural gas, NGLs, ethanol and power through physical purchase and sales contracts, as well as financial commodity contracts. These activities expose us to commodity price risk, as well as foreign currency risk and volatility within these markets. Our energy marketing group actively manages this risk by utilizing energy-related futures, forwards, swaps and options, as well as currency swaps or forwards. We typically take advantage of location, time and quality spreads using physical and financial contracts. The marketing group also tries to take advantage of volatility within commodity markets and can establish net open commodity positions to take advantage of existing market conditions.

Volatility within our various markets can vary and change over time. While this volatility gives us opportunities, it can also cause our results to vary significantly between periods. We attempt to manage associated risk and take on positions based on solid market intelligence; however, it is possible that we could incur financial loss.

Open positions exist when not all contracted purchases and sales terms have been matched. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk sensitivities in our portfolio). Open positions and derivative instruments expose us to other risks, including credit risk and liquidity risk.

We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss, given a 95% confidence level, that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility, correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" (for natural gas since May 2006) distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. Stress testing complements our VaR estimate. It is used to quantify potential unexpected losses from low probability market movements. Credit VaR is reported separately from commodity VaR, and ranged between $3.6 and $6.1 million in 2007.

Our year end, annual high, annual low and annual average VaR amounts are as follows:

(Cdn$ millions)	2007	2006	2005
Value at Risk			
Year End	26	26	24
High	38	33	28
Low	24	17	11
Average	30	23	21

Our board of directors has approved formal risk management policies for our energy trading activities. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the board of directors and our Risk Management Committee monitor our exposure to the above risks and review the results of our energy trading activities regularly.

CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry and are subject to normal industry credit risk. We take the following measures to reduce this risk:

- we assess the financial strength of our counterparties through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- we routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the board;
- we set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2007:

- over 96% of our credit exposures were investment grade; and
- only three counterparties individually made up more than 5% of our credit exposure, one of which made up more than 10%. All three were investment grade.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations*, constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act* of 1995, Section 21E of the United States *Securities Exchange Act of 1934,* as amended, and Section 27A of the United States *Securities Act of 1933,* as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our Yemen operations;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset dispositions;
- future sources of funding for our capital program;
- future debt levels;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves or resources;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- estimates on a per share basis;
- sales;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed or will come on stream; and
- changes in any of the foregoing.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

- market prices for oil and gas and chemicals products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- volatility in energy trading markets;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigations, arbitration or regulatory proceedings; and
- political uncertainty, including actions by terrorists, insurgent or other groups, or armed conflict, including conflict between states.

These items and their possible impact are discussed more fully in the section, titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures about Market Risk* in Item 7A. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In Canada, *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) prescribes that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. Our disclosures may differ from other Canadian companies as we have received exemptions under NI 51-101 permitting us to:

- substitute our SEC disclosures for much of the annual disclosure required by NI 51-101;
- prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) modified to reflect SEC requirements;
- dispense with the requirement to have our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, evaluated or audited by independent qualified reserves evaluators; and
- not disclose certain prescribed information pertaining to prospects if such disclosures would result in the contravention of a legal obligation, would likely be detrimental to our competitive interests or the information does not exist.

As a result of these exemptions, Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein* calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved developed reserves by geographic region only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not prescribe the nature of the information required in connection with proved undeveloped reserves and future development costs whereas NI 51-101 requires certain detailed information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions whereas NI 51-101 requires that various F&D costs per boe be disclosed. NI 51-101 requires that F&D costs be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year;
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports;
- the SEC does not consider the upgrading component of our integrated oil sands project at Long Lake as an oil and gas activity, and therefore permits recognition of bitumen reserves only. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits recognition of synthetic reserves. At year end, we have recognized 268 million barrels before royalties of proved bitumen reserves (234 million barrels after royalties) under SEC requirements, whereas under NI 51-101 we would have recognized 218 million barrels before royalties of proved synthetic reserves (210 million barrels after royalties); and
- the SEC considers our Syncrude operation as a mining activity rather than an oil and gas activity, and therefore does not permit related reserves to be included with oil and gas reserves. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits them to be included with oil and gas reserves. We have provided a separate table showing our share of the Syncrude proved reserves as well as the additional disclosures relating to mining activities required by SEC requirements.

The foregoing is a general description of the principal differences only.

Please note that the differences between SEC requirements and NI 51-101 may be material.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- because reserves data are based on judgments regarding future events actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.

financial **statements**

A strong and robust balance sheet provides the necessary flexibility to ensure we can fund our active capital programs.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF MANAGEMENT

February 13, 2008

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and fair presentation of the consolidated financial statements, as well as the financial reporting process that gives rise to such consolidated financial statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for the development and implementation of internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company, and that our records are reliable for preparing our consolidated financial statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our board of directors is responsible for reviewing and approving the consolidated financial statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors and includes three directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws), pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:
We have audited the accompanying consolidated balance sheets of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, cash flows, shareholders' equity and comprehensive income for each of the years in the three year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Nexen Inc. and subsidiaries as of December 31, 2007 and 2006 and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 13, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 13, 2008

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 1(u) to the consolidated financial statements. Our report to the board of directors and shareholders on the consolidated financial statements of the Company dated February 13, 2008, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 13, 2008

NEXEN INC.
CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2007

Cdn$ millions, except per share amounts	2007	2006	2005
Revenues and Other Income			
Net Sales	5,583	3,936	3,932
Marketing and Other (Note 17)	1,021	1,450	702
Gain on Dilution of Interest in Chemicals Business (Note 2)	–	–	193
	6,604	5,386	4,827
Expenses			
Operating	1,165	955	893
Depreciation, Depletion, Amortization and Impairment (Note 6)	1,767	1,124	1,052
Transportation and Other	908	1,041	796
General and Administrative	374	555	809
Exploration	326	362	250
Interest (Note 8)	168	53	97
	4,708	4,090	3,897
Income from Continuing Operations before Income Taxes	1,896	1,296	930
Provision for Income Taxes (Note 18)			
Current	434	368	339
Future	358	315	(105)
	792	683	234
Net Income from Continuing Operations before Non-Controlling Interests	1,104	613	696
Net Income Attributable to Non-Controlling Interests (Note 2)	18	12	8
Net Income from Continuing Operations	1,086	601	688
Net Income from Discontinued Operations (Note 14)	–	–	452
Net Income	**1,086**	**601**	**1,140**
Earnings Per Common Share from Continuing Operations ($/share)			
Basic (Note 13)	2.06	1.15	1.32
Diluted (Note 13)	2.02	1.12	1.29
Earnings Per Common Share ($/share)			
Basic (Note 13)	2.06	1.15	2.19
Diluted (Note 13)	2.02	1.12	2.14

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2007 AND 2006

Cdn$ millions, except share amounts	2007	2006
ASSETS		
Current Assets		
Cash and Cash Equivalents	206	101
Restricted Cash and Margin Deposits (Note 7(d))	203	197
Accounts Receivable (Note 4)	3,502	2,951
Inventories and Supplies (Note 5)	659	786
Future Income Tax Assets (Note 18)	18	479
Other	71	67
Total Current Assets	4,659	4,581
Property, Plant and Equipment (Note 6)	12,498	11,739
Goodwill	326	377
Future Income Tax Assets (Note 18)	268	141
Deferred Charges and Other Assets (Note 10)	324	318
TOTAL ASSETS	**18,075**	**17,156**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings (Note 8)	–	158
Accounts Payable and Accrued Liabilities	4,180	3,879
Accrued Interest Payable	54	55
Dividends Payable	13	13
Total Current Liabilities	4,247	4,105
Long-Term Debt (Note 8)	4,610	4,673
Future Income Tax Liabilities (Note 18)	2,290	2,468
Asset Retirement Obligations (Note 9)	792	683
Deferred Credits and Other Liabilities (Note 11)	459	516
Non-Controlling Interests (Note 2)	67	75
Shareholders' Equity (Note 12)		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2007—528,304,813 shares		
2006—525,026,412 shares	917	821
Contributed Surplus	3	4
Retained Earnings	4,983	3,972
Accumulated Other Comprehensive Loss	(293)	(161)
Total Shareholders' Equity	5,610	4,636
Commitments, Contingencies and Guarantees (Notes 15 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**18,075**	**17,156**

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Charles W. Fischer"
Director

(signed) "Thomas C. O'Neill"
Director

NEXEN INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 2007

Cdn$ millions	2007	2006	2005
Operating Activities			
Net Income from Continuing Operations	1,086	601	688
Net Income from Discontinued Operations	–	–	452
Charges and Credits to Income not Involving Cash (Note 19)	2,073	1,629	1,081
Exploration Expense	326	362	250
Changes in Non-Cash Working Capital (Note 19)	(348)	(177)	(195)
Other	(307)	(41)	(133)
	2,830	2,374	2,143
Financing Activities			
Proceeds from Long-Term Notes and Debentures (Note 8)	1,660	–	1,253
Repayment of Long-Term Notes and Debentures (Note 8)	(150)	(93)	(1,818)
Proceeds from (Repayment of) Term Credit Facilities, Net	(697)	1,044	(66)
Proceeds from (Repayment of) Short-Term Borrowings, Net	(150)	160	(99)
Dividends on Common Shares	(53)	(52)	(52)
Issue of Common Shares and Exercise of Tandem Options for Shares	56	48	58
Net Proceeds from Canexus Initial Public Offering (Note 2)	–	–	301
Proceeds from Term Credit Facilities of Canexus, Net (Notes 2 and 8)	60	2	176
Other	(49)	(28)	(27)
	677	1,081	(274)
Investing Activities			
Capital Expenditures			
Exploration and Development	(3,132)	(3,198)	(2,564)
Proved Property Acquisitions	(151)	(13)	(20)
Chemicals, Corporate and Other	(118)	(119)	(54)
Business Acquisitions, Net of Cash Acquired (Note 3)	–	(78)	–
Proceeds on Disposition of Assets	4	27	911
Changes in Non-Cash Working Capital (Note 19)	130	134	(54)
Changes in Restricted Cash and Margin Deposits	(16)	(127)	(70)
Other	2	(14)	(13)
	(3,281)	(3,388)	(1,864)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(121)	(14)	(30)
Increase (Decrease) in Cash and Cash Equivalents	105	53	(25)
Cash and Cash Equivalents—Beginning of Year	101	48	73
Cash and Cash Equivalents—End of Year	**206**	**101**	**48**

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2007

Cdn$ millions	2007	2006	2005
Common Shares (Note 12)			
Balance at Beginning of Year	821	732	637
Issue of Common Shares	32	32	29
Proceeds from Tandem Options Exercised for Shares	24	16	29
Accrued Liability Relating to Tandem Options Exercised for Shares	40	41	37
Balance at End of Year	**917**	**821**	**732**
Contributed Surplus			
Balance at Beginning of Year	4	2	–
Stock-Based Compensation Expense (Note 12)	1	2	2
Exercise of Tandem Options	(2)	–	–
Balance at End of Year	**3**	**4**	**2**
Retained Earnings			
Balance at Beginning of Year	3,972	3,423	2,335
Net Income	1,086	601	1,140
Dividends on Common Shares	(53)	(52)	(52)
Transition Adjustment Resulting from Adoption of New Inventory Standard (Note 1u)	(22)	–	–
Balance at End of Year	**4,983**	**3,972**	**3,423**
Accumulated Other Comprehensive Loss			
Balance at Beginning of Year	(161)	(161)	–
Opening Cumulative Foreign Currency Translation Adjustment (Note 1u)	–	–	(105)
Opening Derivatives Designated as Cash Flow Hedges (Note 1u)	61	–	–
Other Comprehensive Loss	(193)	–	(56)
Balance at End of Year [1]	**(293)**	**(161)**	**(161)**

Note:
1 Includes unrealized foreign currency translation adjustment.

NEXEN INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2007

Cdn$ millions	2007	2006	2005
Net Income	1,086	601	1,140
Other Comprehensive Income (Loss), net of income taxes:			
Foreign Currency Translation Adjustment:			
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	(867)	16	(179)
Net Gains (Losses) on Hedges of Self-Sustaining Foreign Operations [1]	738	(20)	99
Realized Translation Adjustments Recognized in Net Income [2]	(3)	4	24
Cash Flow Hedges:			
Realized Mark-to-Market Gains Recognized in Net Income	(61)	–	–
Other Comprehensive Loss, net of income taxes	(193)	–	(56)
Comprehensive Income	**893**	**601**	**1,084**

Notes:
1 Net of income tax expense for the year ended December 31, 2007 of $97 million (2006—$12 million recovery; 2005—$19 million expense).
2 Net of income tax recovery for the year ended December 31, 2007 of $1 million (2006—$1 million expense; 2005—$17 million expense).

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cdn$ millions, except as noted

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 21.

(a) Use of estimates

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, impairments, income taxes, derivative contract assets and liabilities and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(b) Principles of consolidation

The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus LP (see Note 2) and its subsidiaries, are wholly owned and intercompany accounts and transactions have been eliminated.

In August 2005, we sold our chemicals operations to Canexus LP, but retained control of these operations through our 61.4% interest in Canexus LP. All of the assets, liabilities and results of operations of Canexus LP and its subsidiaries have been included in our Consolidated Financial Statements. The non-Nexen ownership interests in Canexus LP and its subsidiaries are shown as non-controlling interests.

We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. We also proportionately consolidate our 7.23% undivided interest in the Syncrude joint venture, which is considered a mining activity under US regulations. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(c) Accounts receivable

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(j)). Our allowance for doubtful accounts provides for specific doubtful receivables.

(d) Inventories and supplies

Inventories and supplies for our oil and gas and chemicals operations are stated at the lower of cost and net realizable value. Cost is determined on the first-in, first-out method. Inventory costs include expenditures and other costs, including depletion, directly or indirectly incurred in bringing the inventory to its existing condition.

Commencing October 1, 2007 (see Note 1(u)), commodity inventories for our energy marketing operations are held for trading purposes and are stated at fair value, as measured by the one-month forward price, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other during the period of change.

(e) Property, plant and equipment (PP&E)

Property, plant and equipment is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included with PP&E.

We follow successful efforts accounting for our oil and gas operations. All property acquisition costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the acquisition costs are reclassified to proved property acquisition costs. Exploration drilling costs are capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized when a well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made to assess the reserves and the economic and operating viability of the well. All other exploration costs, including geological and geophysical and annual lease rentals, are expensed to earnings as incurred. All development costs are capitalized as

proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

PP&E for our Syncrude operation is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established, and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

(f) Depreciation, depletion, amortization and impairment (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs over remaining proved reserves. Depletion is considered a cost of inventory when the oil and gas is produced. When this inventory is sold, the depletion is charged to DD&A expense.

Our Syncrude PP&E is depleted using the unit-of-production method. Capitalized costs are depleted over proved and probable reserves within developed areas of interest.

We depreciate other plant and equipment costs, including our chemicals facilities, using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur that indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. These events or conditions occur periodically. If carrying value exceeds the sum of undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated total future cash flows, discounted for the time value of money, and we expense the excess carrying value to DD&A. Our cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(g) Carried interest

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(h) Asset retirement obligations

We provide for future asset retirement obligations on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The asset retirement obligation accretes until the time the retirement obligation is expected to settle, while the asset retirement cost is amortized over the useful life of the underlying PP&E. We periodically review our estimates for changes in expected amounts or timing of cash flows.

The amortization of the asset retirement cost and the accretion of the asset retirement obligation are included in DD&A. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

(i) Goodwill

Goodwill is recorded at cost and is not amortized. We test goodwill for impairment annually based on estimated future cash flows of the reporting unit to which the goodwill is attributable. In addition, we test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount. If our goodwill is impaired, we write it down to its implied fair value, based on the fair value of the assets and liabilities of the underlying reporting unit. Our goodwill is attributable to our Energy Marketing and UK reporting units.

(j) Revenue recognition

Crude Oil and Natural Gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the crude oil and natural gas reaches the end of the pipeline. For our other international operations, including the UK, our customers take title when crude oil is loaded onto tankers. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty payments to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty payments. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(g).

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery takes place when we have a sales contract in place specifying delivery volumes and sales prices. We assess customer credit worthiness before entering into sales contracts to minimize collection risk.

Energy Marketing

Substantially all of the physical purchase and sales contracts entered into by our energy marketing operations are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our marketing operations are stated at fair value on the balance sheet (see Note 1(n)). We record any change in fair value as a gain or loss in marketing and other unless requirements for hedge accounting are met.

Any margin earned by our marketing operation on the sale of our proprietary oil and gas production is included in marketing and other. Sales of our proprietary production are recorded at monthly average market-based prices and reported in our oil and gas segments. Intercompany profits and losses between segments are eliminated. We assess customer credit worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have the legal right of offset.

(k) Income taxes

We follow the liability method of accounting for income taxes. This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(l) Foreign currency translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using average exchange rates throughout the year.

Gains and losses resulting from this translation are included in other comprehensive income. Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation, except on our designated US-dollar debt, are included in income. We have designated our US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other in the Consolidated Statement of Income.

(m) Capitalized interest

We capitalize interest on major development projects until the project is substantially complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(n) Financial instruments

Financial assets and financial liabilities are recognized on the balance sheet when we become a party to the contractual provisions of the instrument. Our derivative financial instruments are initially recognized at fair value and subsequently remeasured to fair value on each reporting period with changes in fair value recognized in net income. Transaction costs relating to derivative instruments are included in net income when incurred. Our other financial instruments are initially recognized at fair value. After initial recognition, these instruments are measured at cost or amortized cost using the effective interest method and gains and losses are recognized in net income when the assets and liabilities settle.

Non-Trading Activities

We use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Note 7). We record these instruments at fair value at the balance sheet date and record any change in fair value as a net gain or loss in marketing and other during the period of change unless the requirements for hedge accounting are met. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income with any ineffectiveness recognized in net income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Trading Activities

Our energy marketing operation uses derivative instruments for marketing and trading natural gas, crude oil, natural gas liquids, ethanol and power including:

- commodity contracts settled with physical delivery;
- exchange-traded futures and options; and
- non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other during the period of change. The fair value of these instruments is recorded as accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond twelve months, we record them as deferred charges and other assets or deferred credits and other liabilities.

(o) Employee future benefits

The employee future benefit programs consist of both defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in Note 16. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. We measure the plan assets and the accrued benefit obligation on October 31 each year. Company contributions to the defined contribution plan are expensed as incurred.

(p) Stock-based compensation

We maintain tandem option and stock appreciation right (StARs) plans as described in Note 12. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price. We record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense in the Consolidated Statement of Net Income. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital. We account for stock appreciation rights to employees on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

(q) Cash and cash equivalents

Cash and cash equivalents include short-term, highly liquid investments that mature within three months of their purchase. They are recorded at cost, which approximates market value.

(r) Restricted cash and margin deposits

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts.

(s) Leases

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases and the related assets are included with PP&E. These assets are depreciated on the same basis as other PP&E. Rental payments under operating leases are expensed as incurred.

(t) Transportation

We pay to transport the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as a cost to us and is recorded as transportation and other. Our energy marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments have been recorded as deferred liabilities and are recognized in net income as the transportation is used.

(u) Changes in accounting principles

Financial Instruments

On January 1, 2007, we adopted the following new accounting standards issued by the Canadian Accounting Standards Board (AcSB): *Financial Instruments—Recognition and Measurement* (Section 3855), *Hedges* (Section 3865) and *Comprehensive Income* (Section 1530).

Financial Instruments Recognition and Measurement

Section 3855 requires all financial assets and liabilities to be carried at fair value in the Consolidated Balance Sheet with the exception of loans and receivables, investments that are intended to be held to maturity, and non-trading financial liabilities which are to be carried at cost or amortized cost.

Realized and unrealized gains and losses on financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred. Unrealized gains and losses on financial assets and liabilities carried at cost or amortized cost are recognized in net income when these assets or liabilities settle.

We hold financial instruments that were carried at fair value prior to the adoption of Section 3855 as described in Note 7. The valuation methods we use to determine the fair value of these financial instruments remain unchanged. Financial instruments we carry at cost or amortized cost include our accounts receivable, accounts payable, short-term and long-term debt. The carrying value of short-term receivables and payables approximates their fair value. On adoption of Section 3855, we carry our long-term debt at amortized cost using the effective interest rate method. Accordingly, we have reclassified deferred financing costs previously included in deferred charges and other assets as unamortized debt issue costs, reducing the carrying value of our long-term debt.

Hedges

Section 3865 prescribes new standards for hedge accounting. For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income with any ineffectiveness recognized in net income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Adoption of these new standards for hedge accounting required us to record unrealized mark-to-market gains on cash flow hedges that were previously not included on our Consolidated Balance Sheet at December 31, 2006, as an adjustment to the opening balance of accumulated other comprehensive income (see Note 7).

Comprehensive Income

Section 1530 provides for a new statement of comprehensive income and establishes accumulated other comprehensive income (AOCI) as a separate component of shareholders' equity. The statement of comprehensive income reflects changes in AOCI and includes the effective portion of changes in the fair value of financial instruments designated as cash flow hedges, as well as changes in foreign currency translation amounts arising from our self-sustaining foreign operations, together with the impact of any related hedges. Amounts included in AOCI are reclassified to income when realized. On adoption of Section 1530, cumulative foreign currency translation adjustments relating to our self-sustaining foreign operations were reclassified to AOCI and comparative amounts have been restated.

Impact of Adoption

We adopted these standards prospectively. Comparative amounts for prior periods have not been restated with the exception of amounts related to cumulative foreign currency translation adjustments. Adoption of these standards as at January 1, 2007 had the following impact on our Consolidated Balance Sheet:

	As at January 1, 2007 Increase/(Decrease)
To Include Unrealized Mark-to-Market Gains on Cash Flow Hedges at December 31, 2006:	
Accounts Receivable	25
Accounts Payable	(65)
Future Income Tax Liabilities	29
Accumulated Other Comprehensive Income	61
To Include Cumulative Foreign Currency Translation in Accumulated Other Comprehensive Income:	
Cumulative Foreign Currency Translation Adjustment	161
Accumulated Other Comprehensive Income	(161)
To Include Unamortized Debt Issue Costs with Long-Term Debt:	
Deferred Charges and Other Assets	(59)
Long-Term Debt	(59)

Inventories

The AcSB issued Section 3031, *Inventories*, which is effective January 1, 2008. We adopted this standard prospectively in the fourth quarter of 2007 in accordance with the transitional provisions. Effective October 1, 2007, we began carrying the commodity inventories held for trading by our energy marketing group at fair value, less any costs to sell. Section 3031 also clarifies that major spare parts and standby equipment not in use should be included in PP&E. On adoption of Section 3031, we reclassified $51 million from inventories and supplies to PP&E related to major spare parts.

Prior periods presented have not been restated and adoption of the standard had the following impact:

	As at October 1, 2007 Increase/(Decrease)	**Three Months Ended December 31, 2007** Increase/(Decrease)
Inventories and Supplies	(86)	79
Property, Plant and Equipment	51	–
Future Income Tax Liabilities	(13)	27
Retained Earnings	(22)	–
Marketing and Other		79
Provision for Future Income Taxes		27
Net Income		52
Basic/Diluted Earnings per Share ($/share)		$0.10

New Accounting Pronouncements

In December 2006, the AcSB issued two new sections in relation to financial instruments: Section 3862, *Financial Instruments—Disclosures*, and Section 3863, *Financial Instruments—Presentation*. Both sections are effective for annual and interim periods for fiscal years beginning on or after October 1, 2007 and will require additional disclosures for our financial instruments.

In December 2006, the AcSB issued Section 1535, *Capital Disclosures*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital. The standard is effective for annual periods beginning on or after October 1, 2007 and will require additional disclosure.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We are currently evaluating the impact these sections will have on our results of operation and financial position.

In January 2006, the AcSB adopted a strategic plan for the direction of accounting standards in Canada. Accounting standards for public companies in Canada are expected to converge with the International Financial Reporting Standards by 2011. The timing for convergence has not been confirmed by the AcSB. We continue to monitor and assess the impact of these convergence efforts.

2. CANEXUS INCOME FUND

In June 2005, our board of directors approved a plan to monetize our chemicals operations through the creation of an income trust and the issuance of trust units in an initial public offering. This initial public offering closed on August 18, 2005, with Canexus Income Fund (Canexus) issuing 30 million units at a price of $10 per unit for gross proceeds of $300 million ($284 million, net of underwriters' commissions).

Concurrent with the closing of the offering, Canexus acquired a 36.5% interest in Canexus Limited Partnership (Canexus LP) using the net proceeds from the initial public offering. Canexus LP acquired Nexen's chemicals business for approximately $1 billion, comprised of the net proceeds from Canexus' initial public offering and $200 million (US$167 million) of bank debt, plus the issuance of 52.3 million exchangeable limited partnership units (Exchangeable LP Units) of Canexus LP. At that time, the Exchangeable LP Units held by Nexen represented a 63.5% interest in Canexus LP.

The Exchangeable LP Units held by Nexen are exchangeable on a one-for-one basis for trust units of Canexus. As a result, the Exchangeable LP Units owned by Nexen were exchangeable into 52.3 million trust units which represented 63.5% of the outstanding trust units of Canexus assuming exchange of the Exchangeable LP Units.

On September 16, 2005, the underwriters of the initial public offering exercised a portion of their over-allotment option to purchase 1.75 million trust units at $10 per unit for gross proceeds of $18 million ($17 million, net of underwriters' commissions). As a result, Nexen exchanged 1.75 million of its Exchangeable LP Units for $17 million in net proceeds. After this exchange, Nexen has a 61.4% interest in Canexus LP represented by 50.5 million Exchangeable LP Units. The initial public offering, together with the exercise of the over-allotment, resulted in total net proceeds to Nexen of $301 million.

These transactions diluted our interest in our chemicals operations. As a result of this dilution, we recorded a gain of $193 million during the third quarter of 2005.

We have the right to nominate a majority of the members of the board of Canexus Limited, the corporation, with responsibility for the strategic management and operational decisions of Canexus and Canexus LP. Nexen currently has nominated two representatives to the ten-member board of Canexus Limited. Since we have retained effective control of our chemicals business, the results, assets and liabilities of this business have been included in these financial statements. The non-Nexen ownership interests in our chemicals business are shown as non-controlling interests.

During the year, $28 million (2006—$28 million; 2005—$10 million) of distributions were paid to non-Nexen ownership interests.

3. BUSINESS ACQUISITIONS

In 2006, we completed minor business acquisitions related to our marketing group for $78 million, net of cash acquired. These acquisitions were accounted for using the purchase method of accounting. The assets and liabilities purchased were primarily working capital and we recorded goodwill of $12 million as a result of the acquisitions.

4. ACCOUNTS RECEIVABLE

	2007	2006
Trade		
Marketing	2,501	2,226
Oil and Gas	819	600
Chemicals and Other	60	58
	3,380	2,884
Non-Trade	132	80
	3,512	2,964
Allowance for Doubtful Receivables	(10)	(13)
Total Accounts Receivable	**3,502**	**2,951**

5. INVENTORIES AND SUPPLIES

	2007	2006
Finished Products		
Marketing [1]	577	609
Oil and Gas	14	21
Chemicals and Other	13	14
	604	644
Work in Process	3	5
Field Supplies (Note 1(u))	52	137
Total Inventories and Supplies	**659**	**786**

Note:

1 Marketing consists of commodity inventories held for trading purposes. At December 31, 2006, these inventories were carried at the lower of cost and net realizable value. On October 1, 2007, we adopted Section 3031 and at December 31, 2007, marketing inventories are carried at fair value less any costs to sell. (see Note 1(u)).

6. PROPERTY, PLANT AND EQUIPMENT

	2007			2006		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	701	590	111	779	599	180
Yemen—Carried Interest	1,477	1,360	117	1,625	1,529	96
Canada [1]	6,736	1,597	5,139	5,216	1,448	3,768
United States	3,069	1,765	1,304	2,889	1,445	1,444
United Kingdom	4,723	908	3,815	4,710	432	4,278
Other Countries	263	77	186	249	78	171
	16,969	6,297	10,672	15,468	5,531	9,937
Marketing	246	62	184	226	47	179
Syncrude	1,332	205	1,127	1,304	179	1,125
Chemicals	831	463	368	854	494	360
Corporate and Other	315	168	147	286	148	138
Total PP&E	**19,693**	**7,195**	**12,498**	**18,138**	**6,399**	**11,739**

Note:

1 Includes capitalized costs related to our Long Lake (Phase 1 and future phases) of $3,695 million (2006—$2,556 million).

The above table includes capitalized costs of $5,828 million (2006—$6,708 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized. Our Long Lake capitalized costs include $1,711 million related to the Phase 1 upgrader (2006—$1,120 million), $1,026 million for Phase 1 SAGD and cogeneration facilities (2006—$804 million) and $958 million related to capitalized interest and future phases (2006—$632 million).

Depreciation, Depletion, Amortization and Impairment (DD&A)

In 2007, our DD&A expense includes $366 million of impairment expense primarily related to our Aspen, Vermillion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our recent investment in development drilling resulted in negative reserve revisions. At Vermillion 320/340 and West Cameron 170, negative reserve revisions primarily relate to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. These properties were written down to their fair value equal to their estimated total future cash flows, discounted for the time value of money.

Our 2006 DD&A expense includes $93 million of impairment expense, primarily related to two natural gas producing properties in the Gulf of Mexico in the US caused by unsuccessful development programs and negative year-end reserve revisions. In addition there was $15 million in 2006 relating to the write off of a portion of our purchase price allocation to unproved properties purchased in the North Sea as a result of unsuccessful exploration activities.

Research and Development

We incurred $40 million (2006—$53 million) in connection with research and development activities related to developing new technologies for increasing oil recoveries. Research costs of $38 million (2006—$50 million) were included in other expense on the Consolidated Statement of Income. The development costs have been deferred and are included in PP&E.

	2007	2006
Development Costs Deferred, Beginning of Year	28	25
Deferred in the Year	2	3
Amortized in the Year	–	–
Development Costs Deferred, End of Year	**30**	**28**

Suspended Well Costs

The following table shows the changes in capitalized exploratory well costs during the years ended December 31, 2007 and 2006, and does not include amounts that were initially capitalized and subsequently expensed in the same period.

	2007	2006
Balance at Beginning of Year	226	252
Additions to Capitalized Exploratory Well Costs Pending the Determination of Proved Reserves	215	129
Capitalized Exploratory Well Costs Charged to Expense	(10)	(70)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(74)	(84)
Effects of Foreign Exchange	(31)	(1)
Balance at End of Year	**326**	**226**

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	2007	2006
Capitalized for a Period of One Year or Less	202	179
Capitalized for a Period of Greater than One Year	124	47
Balance at End of Year	**326**	**226**
Number of Projects that have Exploratory Well Costs Capitalized for a Period Greater than One Year	5	4

As at December 31, 2007, we have exploratory costs that have been capitalized for more than one year relating to our interest in an exploratory block in the Gulf of Mexico ($51 million), our coalbed methane exploratory activities in Canada ($31 million), exploratory activities on Block 51 in Yemen ($18 million), our interest in an exploratory block offshore Nigeria ($18 million) and an exploratory block in the North Sea ($6 million). These costs relate to projects with successful exploration wells for which we have not been able to record proved reserves. We are assessing all of these wells and projects, and are working with our partners to prepare development plans, drill additional appraisal wells or to assess commercial viability.

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

We use derivatives in our marketing group for trading purposes and we also use derivatives to manage commodity price risk and foreign currency exchange rate risk for non-trading purposes. Our derivative instruments are carried at fair value on the balance sheet. Our other financial instruments are carried at cost or amortized cost. The carrying value of short-term receivables and payables approximates their fair value because the instruments are near maturity.

(a) Carrying value and estimated fair value of derivative and financial instruments

The carrying values, fair values and unrecognized gains or losses on our outstanding derivatives and long-term financial assets and liabilities at December 31 are:

	2007			2006		
	Carrying Value	Fair Value	Unrecognized Gain (Loss)	Carrying Value	Fair Value	Unrecognized Gain (Loss)
Commodity Price Risk						
Non-Trading Activities						
Crude Oil Put Options	–	–	–	19	19	–
Fixed-Price Natural Gas Contracts	(70)	(70)	–	(96)	(96)	–
Natural Gas Swaps	(9)	(9)	–	(8)	(8)	–
Trading Activities						
Crude Oil and Natural Gas	15	15	–	372	372	–
Future Sale of Gas Inventory	–	–	–	–	25	25
Foreign Currency Exchange Rate Risk						
Non-Trading Activities	1	1	–	–	–	–
Trading Activities	(9)	(9)	–	(12)	(12)	–
Total Derivatives	**(72)**	**(72)**	–	**275**	**300**	**25**
Other Financial Liabilities						
Long-Term Debt	(4,610)	(4,692)	(82)	(4,673)	(4,728)	(55)

The estimated fair value of all derivative instruments is based on quoted market prices and, if not available, on estimates from third-party brokers or dealers. Other financial assets used in the normal course of business include cash and cash equivalents, restricted cash and margin deposits and accounts receivable. Other financial liabilities include accounts payable, accrued interest payable, short-term borrowings and long-term debt. Fair value of long-term debt is estimated based on third-party brokers and quoted market prices.

(b) Commodity price risk management

Non-Trading Activities

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

Crude oil put options

In 2007, we purchased put options on 36 million barrels or approximately 100,000 bbls/d of our 2008 crude oil production. These options established an annual average Dated Brent floor price of US$50/bbl on these volumes. The put options were purchased for $24 million and the fair value at December 31, 2007 was $nil. We recorded a loss of $24 million in marketing and other on the Consolidated Statement of Income in 2007.

In 2006, we purchased WTI crude oil put options on 105,000 bbls/d of our 2007 crude oil production at a cost of $26 million. These options established an annual average WTI floor price of US$50/bbl on these volumes. The 2007 WTI crude oil put options were not used and have expired. The fair value at the end of December 31, 2006 was $19 million, which we included as a loss of $19 million in marketing and other on the Consolidated Statement of Income in 2007.

Fixed price natural gas contracts and natural gas swaps

In July and August 2005, we sold certain Canadian oil and gas properties, and we retained fixed-price natural gas sales contracts that were previously associated with those properties (see Note 14). Since these contracts are no longer used in the normal course of our oil and gas operations, they have been included in our Consolidated Balance Sheet at fair value. Amounts settling within 12 months are included in accounts payable and amounts settling beyond that are included in deferred credits and other liabilities. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

	Notional Volumes (Gj/d)	Term	Average Price ($/Gj)	Fair Value (Cdn$ millions)
Fixed-Price Natural Gas Contracts	15,514	2008	2.46	(22)
	15,514	2009-2010	2.56-2.77	(48)
				(70)

Following the sale of the Canadian oil and gas properties, we entered into natural gas swaps to economically hedge our exposure to the fixed-price natural gas contracts. The natural gas swaps are included in our Consolidated Balance Sheet with amounts settling within 12 months included in accounts payable and amounts settling beyond that are included in deferred credits and other liabilities. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

	Notional Volumes (Gj/d)	Term	Average Price ($/Gj)	Fair Value (Cdn$ millions)
Natural Gas Swaps	15,514	2008	7.60	(6)
	15,514	2009-2010	7.60	(3)
				(9)

Trading Activities

Crude oil and natural gas

We enter into physical purchase and sales contracts as well as financial commodity contracts to enhance our price realizations and lock-in our margins. The physical and financial commodity contracts (derivative contracts) are stated at fair value. The $15 million fair value of the commodity contracts at December 31, 2007 (December 31, 2006—$372 million) is included in the Consolidated Balance Sheet and any change in fair value is included in marketing and other in the Consolidated Statement of Income.

Future sale of gas inventory

In an attempt to mitigate the exposure to fluctuations in cash flow from changes in the price of natural gas we have certain NYMEX futures contracts and swaps in place, which effectively lock in our margins on the future sale of our natural gas inventory in storage. From time to time, we have designated in writing some of these derivative contracts as cash flow hedges of the future sale of our storage inventory.

At December 31, 2006, we held NYMEX natural gas futures contracts and swaps that were designated as cash flow hedges on the future sale of natural gas inventory. On adoption of Section 3865 on January 1, 2007 (see Note 1(u)), the fair value of $25 million related to these cash flow hedges was included in accounts receivable and gains of $16 million, net of income taxes, were included in accumulated other comprehensive income (AOCI). During the first quarter of 2007, the inventory was sold and these gains were recognized in marketing and other in the Consolidated Statement of Income.

In late 2006, we de-designated certain futures contracts that were designated as cash flow hedges of future sales of our natural gas in storage. These contracts were de-designated since it became uncertain at that time that the future sales of natural gas would occur within the designated time frame. As it was reasonably possible that the future sales could have taken place as designated at the inception of the hedging relationship, gains of $65 million on the futures contracts were deferred in accounts payable at December 31, 2006. The adoption of Section 3865 on January 1, 2007 (see Note 1 (u)) required that the deferred gains ($45 million, net of income taxes) be reclassified to AOCI. The gains were recognized in marketing and other in the Consolidated Statement of Income during the first quarter of 2007.

At December 31, 2007, there were no designated cash flow hedges in place.

(c) Foreign currency exchange rate risk management

Non-Trading Activities

US dollar call options—Canexus

The operations of Canexus are exposed to changes in the US-dollar exchange rate as a portion of its sales are denominated in US dollars while most of its costs are in Canadian dollars. Canexus periodically purchases US-dollar call options to reduce this exposure to fluctuations in the Canadian-US dollar exchange rate. Under outstanding option contracts at December 31, 2007, Canexus LP has the right to sell US$5 million monthly and purchase Canadian dollars at an exchange rate of US$0.95 for the period September 1, 2007 to February 29, 2008. The fair value of these contracts at December 31, 2007 was $1 million. Changes in fair value are included in marketing and other in the Consolidated Statement of Income.

Other

The foreign exchange gains or losses related to our designated debt are included in accumulated other comprehensive income in shareholders' equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31 are as follows:

(US$ millions)	2007	2006
Net Investment in Self-Sustaining Foreign Operations	4,667	4,534
Designated US-Dollar Debt	4,414	3,761

We also have small exposures to currencies other than the US dollar. A portion of our United Kingdom operating expenses, capital spending and future asset retirement obligations are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies.

Trading Activities

Our sales and purchases of crude oil and natural gas are generally transacted in or referenced to the US dollar, as are most of the financial commodity contracts used by our marketing group. However, we pay for many of our purchases in Canadian dollars. We enter into US-dollar forward contracts and swaps to manage this exposure. Losses of $9 million on our US-dollar forward contracts and swaps at December 31, 2007 (December 31, 2006—$12 million loss) are included in the Consolidated Balance Sheet. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

(d) Total carrying value of derivative contracts related to trading activities

Amounts related to derivative instruments held by our marketing operation are equal to fair value as we use mark-to-market accounting, and are as follows at December 31:

	2007	2006
Accounts Receivable	334	731
Deferred Charges and Other Assets [1] (Note 10)	248	153
Total Derivative Contract Assets	**582**	**884**
Accounts Payable and Accrued Liabilities	413	325
Deferred Credits and Other Liabilities [1] (Note 11)	163	199
Total Derivative Contract Liabilities	**576**	**524**
Total Derivative Contract Net Assets [2]	**6**	**360**

Notes:

1 These derivative instruments settle beyond twelve months and are considered non-current.

2 Comprised of $15 million (2006—$372 million) related to commodity contracts and losses of $9 million (2006—$12 million loss) related to US-dollar forward contracts and swaps.

Our exchange-traded derivative contracts are subject to margin requirements. We have margin deposits of $203 million (December 31, 2006—$197 million), which have been included in restricted cash and margin deposits on our Consolidated Balance Sheet at December 31, 2007.

(e) Interest rate risk management

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. We manage this exposure by maintaining a combination of fixed and floating rate borrowings and facilities. At December 31, 2007, fixed-rate borrowings comprised 91% (2006—73%) of our long-term debt at an effective average rate of 6.3% (2006—6.3%). During the year, we periodically drew on our floating-rate term credit facilities. The average interest rate for our floating rate borrowings was 5.8% for the year (2006—5.7%).

(f) Credit risk management

A substantial portion of our accounts receivable are with counterparties in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We assess the financial strength of our counterparties, including those involved in marketing and other commodity arrangements, and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event of a downgrade to a non-investment grade credit rating occurs. Credit risk, including credit concentrations, is routinely reported to our Risk Management Committee. We also use standard agreements that allow for the netting of exposures associated with a single counterparty. We believe this minimizes our overall credit risk. At December 31, 2007, over 96% of our credit exposures were investment grade quality and only three counterparties individually made up more than 5% of our credit exposure.

8. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	2007	2006
Canexus LP Term Credit Facilities (US$204 million) (a)	202	174
Term Credit Facilities (US$214 million) (b)	211	1,078
Medium-Term Notes, due 2007 (c)	–	150
Medium-Term Notes, due 2008 (d)	125	125
Notes, due 2013 (US$500 million) (e)	494	583
Notes, due 2015 (US$250 million) (f)	247	291
Notes, due 2017 (US$250 million) (g)	247	–
Notes, due 2028 (US$200 million) (h)	198	233
Notes, due 2032 (US$500 million) (i)	494	583
Notes, due 2035 (US$790 million) (j)	781	920
Notes, due 2037 (US$1,250 million) (k)	1,235	–
Subordinated Debentures, due 2043 (US$460 million) (l)	454	536
	4,688	**4,673**
Unamortized Debt Issue Costs (Note 1(u))	(78)	–
Total	**4,610**	**4,673**

(a) Canexus LP term credit facilities

Canexus LP has $350 million of committed, secured term credit facilities, which are available until 2010. At December 31, 2007, $202 million (US$204 million) was drawn on these facilities (2006—$174 million). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at floating rates. The term credit facilities are secured by a floating charge debenture over all of Canexus LP's assets and by certain guarantees, security interests and subordination agreements provided by certain affiliates of Canexus LP (which do not include Nexen). The credit facility also contains covenants with respect to certain financial ratios. During 2007, the weighted-average interest rate on the Canexus LP term credit facilities was 6.1% (2006—5.9%).

(b) Term credit facilities

We have unsecured term credit facilities of US$3 billion, which are available until 2012. At December 31, 2007, $211 million (US$214 million) was drawn on these facilities (2006—$1,078 million). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During 2007, the weighted-average interest rate was 5.8% (2006—5.7%). At December 31, 2007, $283 million of these facilities were utilized to support outstanding letters of credit (December 31, 2006—$294 million).

(c) Medium-term notes, due 2007

During July 1997, we issued $150 million of notes with interest payable semi-annually at a rate of 6.45%. The principal of $150 million was repaid in full in July 2007.

(d) Medium-term notes, due 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3%, and the principal is to be repaid in June 2008. Amounts due June 2008 have not been included in current liabilities as we expect to repay this amount using our term credit facilities.

(e) Notes, due 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05%, and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(f) Notes, due 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.2%, and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.15%.

(g) Notes, due 2017

During May 2007, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.65%, and the principal is to be repaid in May 2017. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%. The proceeds were used to repay outstanding term credit facilities.

(h) Notes, due 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4%, and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

(i) Notes, due 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875%, and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%.

(j) Notes, due 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875%, and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(k) Notes, due 2037

During May 2007, we issued US$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4%, and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.35%. The proceeds were used to repay outstanding term credit facilities.

(l) Subordinated debentures, due 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(m) Long-term debt repayments

2008	125
2009	–
2010	202
2011	–
2012	211
Thereafter	4,150
Total	**4,688**

(n) Debt covenants

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2007, we were in compliance with all covenants.

(o) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $665 million, none of which were drawn at December 31, 2007 (2006—$158 million). We have also utilized $196 million of these facilities to support outstanding letters of credit at December 31, 2007 (2006—$252 million). Interest is payable at floating rates. During 2007, the weighted-average interest rate on our short-term borrowings was 5.8% (2006—5.5%).

(p) Interest expense

	2007	2006	2005
Long-Term Debt	323	275	260
Other	18	19	15
Total	341	294	275
Less: Capitalized	(173)	(241)	(178)
Total Interest Expense	**168**	**53**	**97**

Capitalized interest relates to and is included as part of the cost of oil and gas and Syncrude properties. The capitalization rates are based on our weighted-average cost of borrowings.

9. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

	2007	2006
Balance at Beginning of Year	704	611
Obligations Incurred with Development Activities	105	75
Obligations Discharged with Disposed Properties	–	(1)
Expenditures Made on Asset Retirements	(23)	(44)
Accretion	44	37
Revisions to Estimates	79	(10)
Effects of Foreign Exchange	(77)	36
Balance at End of Year [1, 2]	**832**	**704**

Notes:

1 Obligations due within twelve months of $40 million (2006—$21 million) have been included in accounts payable and accrued liabilities

2 Obligations relating to our oil and gas activities amount to $786 million (2006—$658 million) and obligations relating to our chemicals business amount to $46 million (2006—$46 million).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,165 million. We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 5.9%. Approximately $137 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile. The estimated future recoverable reserves at Syncrude are significant and given the long life of this asset, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant can continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the lives of the assets are determinable.

10. DEFERRED CHARGES AND OTHER ASSETS

	2007	2006
Long-Term Marketing Derivative Contracts (Note 7d)	248	153
Deferred Financing Costs (Note 1(u))	–	59
Asset Retirement Remediation Fund	13	13
Crude Oil Put Options (Note 7b)	–	19
Other	63	74
Total	**324**	**318**

11. DEFERRED CREDITS AND OTHER LIABILITIES

	2007	2006
Long-Term Marketing Derivative Contracts (Note 7d)	163	199
Deferred Transportation Revenue	82	89
Fixed-Price Natural Gas Contracts (Note 7b)	48	74
Defined Benefit Pension Obligations (Note 16)	57	48
Capital Lease Obligations	52	48
Other	57	58
Total	**459**	**516**

12. SHAREHOLDERS' EQUITY

(a) Authorized capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

Our shareholders approved a split of our issued and outstanding common shares on a two-for-one basis at our annual and special meeting on April 26, 2007. All common shares, per common share amounts, tandem options and stock appreciation rights together with their related weighted-average exercise prices, have been restated to retroactively reflect the share split.

(b) Issued common shares and dividends

(thousands of shares)	2007	2006	2005
Beginning of Year	525,026	522,281	516,798
Issue of Common Shares for Cash			
Exercise of Tandem Options	2,257	1,693	3,647
Dividend Reinvestment Plan	523	552	1,210
Employee Flow-through Shares	499	500	626
End of Year	**528,305**	**525,026**	**522,281**
Dividends Declared per Common Share ($/share)	**0.10**	**0.10**	**0.10**
Cash Consideration (Cdn$ millions)			
Exercise of Tandem Options	24	16	29
Dividend Reinvestment Plan	16	16	20
Employee Flow-through Shares	16	16	9
	56	**48**	**58**

During the year we increased the number of common shares reserved under the Dividend Reinvestment Plan by 4 million shares. At December 31, 2007, there were 4,475,095 common shares (2006—997,662; 2005—1,549,830) reserved for issuance under the Dividend Reinvestment Plan. Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

(c) Tandem options

We have granted tandem options to purchase common shares to directors, officers and employees. Each tandem option permits the holder to purchase one Nexen common share at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price. Options granted prior to February 2001 vest over four years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over three years and are exercisable on a cumulative basis over five years. At the time of grant, the exercise price equals the market price.

Following the introduction of the *American Job Creation Act of 2004* in the US, stock options awarded to our US employees between December 1, 2004 and December 1, 2005 did not include a tandem option cash feature. We use the fair-value method to recognize compensation expense associated with these options. The expense is recognized over the vesting period of the options with a corresponding increase to contributed surplus. This resulted in compensation expense in 2007 of $1 million (2006—$2 million; 2005—$2 million), which was included in general and administrative expense. In 2005, US tax regulations were modified and as a result, tandem options have been issued to our US employees after December 1, 2005. These options are expensed using the intrinsic-method.

The following options have been granted:

	2007		2006		2005	
	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)
Balance at Beginning of Year	30,485	17	30,629	14	32,553	10
Granted	4,007	28	4,802	32	6,783	27
Exercised for Stock	(2,257)	10	(1,693)	9	(3,647)	8
Surrendered for Cash	(4,414)	11	(3,043)	9	(4,178)	9
Forfeited	(418)	22	(210)	19	(882)	11
Balance at End of Year	**27,403**	**20**	**30,485**	**17**	**30,629**	**14**
Options Exercisable at End of Year	18,216	16	18,691	12	16,262	9
Common Shares Reserved for Issuance Under the Tandem Option Plan	29,430		32,470		34,580	

The range of exercise prices of options outstanding and exercisable at December 31, 2007 is as follows:

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Years to Expiry (years)	Number of Options (thousands)	Weighted Average Exercise Price ($/option)
To $4.99	348	4	1	348	4
$5.00 to $9.99	3,807	8	3	3,807	8
$10.00 to $14.99	8,529	12	2	8,508	12
$15.00 to $19.99	15	19	3	9	19
$20.00 to $24.99	1,054	23	3	664	23
$25.00 to $29.99	9,549	28	4	3,510	27
$30.00 to $34.99	4,081	32	4	1,370	32
$35.00 to $39.99	20	36	4	–	–
Total Options	**27,403**			**18,216**	

(d) Stock appreciation rights

Under our stock appreciation rights (StARs) plan established in 2001, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares. At the time of grant, the exercise price equals the market price. The following stock appreciation rights have been granted:

	2007		2006		2005	
	StARs (thousands)	Weighted Average Exercise Price ($/StAR)	StARs (thousands)	Weighted Average Exercise Price ($/StAR)	StARs (thousands)	Weighted Average Exercise Price ($/StAR)
Balance at Beginning of Year	13,890	21	11,928	15	12,871	11
Granted	4,195	29	4,509	32	2,886	27
Exercised for Cash	(2,349)	12	(2,165)	10	(2,909)	9
Forfeited	(301)	26	(382)	19	(920)	12
Balance at End of Year	**15,435**	**24**	**13,890**	**21**	**11,928**	**15**
StARs Exercisable at End of Year	7,525	19	6,151	13	4,852	10

The range of exercise prices of StARs outstanding and exercisable at December 31, 2007 is as follows:

	Outstanding StARs			Exercisable StARs	
	Number of StARs (thousands)	Weighted Average Exercise Price ($/StAR)	Weighted Average Years to Expiry (years)	Number of StARs (thousands)	Weighted Average Exercise Price ($/StAR)
$5.00 to $9.99	160	8	1	160	8
$10.00 to $14.99	4,305	12	2	4,301	12
$15.00 to $19.99	45	17	2	25	17
$20.00 to $24.99	81	23	3	50	23
$25.00 to $29.99	6,914	28	4	1,718	27
$30.00 to $34.99	3,883	32	4	1,271	32
$35.00 to $39.99	47	36	4	–	–
Total StARs	**15,435**			**7,525**	

13. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share from continuing operations using net income from continuing operations divided by the weighted-average number of common shares outstanding. We calculate basic earnings per common share using net income and the weighted-average number of common shares outstanding. We calculate diluted earnings per common share from continuing operations and diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2007	2006	2005
Weighted-Average Number of Common Shares Outstanding	527.1	524.2	520.7
Shares Issuable Pursuant to Tandem Options	26.6	27.7	26.8
Shares to be Purchased from Proceeds of Tandem Options	(15.7)	(14.0)	(14.8)
Weighted-Average Number of Diluted Common Shares Outstanding	**538.0**	**537.9**	**532.7**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2007, we excluded 49,333 options (2006—422,566; 2005—561,416), because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding tandem options were the only potential dilutive instruments.

14. DISCONTINUED OPERATIONS

In the third quarter of 2005, we sold certain Canadian conventional oil and gas properties in southeast Saskatchewan, northwest Saskatchewan, northeast British Columbia and the Alberta foothills. The results of operations of these properties have been presented as discontinued operations. The sales closed in the third quarter of 2005 with net proceeds of $900 million after closing adjustments, and we realized gains of $225 million. These gains are net of losses attributable to pipeline contracts and fixed-price gas sales contracts associated with these properties that we have retained, but no longer use in connection with our oil and gas business.

The results of operations from these properties in Canada are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2005
Revenues and Other Income	
Net Sales	154
Gain on Disposition of Assets	225
	379
Expenses	
Operating	27
Depreciation, Depletion, Amortization and Impairment	28
Exploration Expense	1
Income before Income Taxes	323
Recovery of Future Income Taxes	(129)
Net Income from Discontinued Operations	**452**
Earnings per Common Share ($/share)	
Basic (Note 13)	0.87
Diluted (Note 13)	0.85

There were no assets and liabilities related to discontinued operations as at December 31, 2007 and 2006.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

	2008	2009	2010	2011	2012	Thereafter
Operating Leases	76	102	99	92	84	157
Transportation and Storage Commitments	368	153	118	89	62	132
Drilling Rig Commitments	107	98	187	276	153	–
	551	**353**	**404**	**457**	**299**	**289**

We have a number of lawsuits and claims pending including income tax reassessments (see Note 18), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2007, total rental expense was $53 million (2006—$49 million; 2005—$47 million).

From time to time, we enter into certain types of contracts that require us to indemnify parties against possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary, and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities, would not have a material adverse effect on our liquidity, financial condition or results of operations.

16. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen and Canexus have contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan. Under the defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1%, to a maximum increase of 5%.

(a) Defined benefit pension plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2007			2006		
	Nexen	Canexus	Syncrude	Nexen	Canexus	Syncrude
Change in Projected Benefit Obligation (PBO)						
Beginning of Year	252	58	116	223	49	109
Service Cost	18	3	5	16	3	5
Interest Cost	13	3	6	12	3	5
Plan Participants' Contributions	4	1	1	3	1	1
Actuarial Loss/(Gain)	(2)	(3)	1	9	2	–
Benefits Paid	(13)	–	(4)	(11)	–	(4)
End of Year [1]	**272**	**62**	**125**	**252**	**58**	**116**
Change in Fair Value of Plan Assets						
Beginning of Year	185	50	69	146	40	58
Actual Return on Plan Assets	18	1	2	23	6	8
Employer's Contribution	6	3	6	24	3	5
Plan Participants' Contributions	4	1	1	3	1	1
Benefits Paid	(13)	–	(4)	(11)	–	(3)
End of Year	**200**	**55**	**74**	**185**	**50**	**69**
Reconciliation of Funded Status						
Funded Status [2]	(72)	(7)	(51)	(67)	(8)	(47)
Unamortized Transitional Obligation	–	–	–	–	–	–
Unamortized Prior Service Costs	2	–	–	3	–	–
Unamortized Net Actuarial Loss	31	6	36	39	7	32
Pension Liability	**(39)**	**(1)**	**(15)**	**(25)**	**(1)**	**(15)**
Pension Liability Recognized						
Deferred Charges and Other Assets	4	–	–	10	–	–
Accounts Payable and Accrued Liabilities	(2)	–	–	(1)	–	(2)
Other Deferred Credits and Liabilities (Note 11)	(41)	(1)	(15)	(34)	(1)	(13)
Pension Liability	**(39)**	**(1)**	**(15)**	**(25)**	**(1)**	**(15)**
Assumptions (%)						
Accrued Benefit Obligation at December 31						
Discount Rate	5.25	5.25	5.25	5.00	5.00	5.00
Long-Term Rate of Employee Compensation Increase	4.00	4.00	5.00	4.00	4.00	4.00
Benefit Cost for Year Ended December 31 [3]						
Discount Rate	5.00	5.00	5.25	5.25	5.25	5.00
Long-Term Rate of Employee Compensation Increase	4.00	4.00	5.00	4.00	4.00	4.00
Long-Term Annual Rate of Return on Plan Assets [4]	7.00	6.50	8.50	7.00	6.50	8.50

Notes:

1 *The accumulated benefit obligations (the projected benefit obligation excluding future salary increases) of the Nexen and Canexus plans were $182 million and $47 million at December 31, 2007, respectively (2006—$180 million and $44 million, respectively). Nexen's supplemental pension plan's accumulated benefit obligation was $48 million at December 31, 2007 (2006—$35 million). Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $92 million at December 31, 2007 (2006—$89 million).*

2 *Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2007, the PBO for Nexen's supplemental benefits was $62 million (2006—$53 million) and $1 million for Canexus (2006—$1 million).*

3 *The assumptions have been used to calculate the recognized expense for Nexen and Canexus. There were no changes to the assumptions between the measurement date of October 31, 2007 and December 31, 2007. Syncrude's measurement date was December 31, 2007.*

4 *The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.*

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2007	2006	2005
Nexen			
Cost of Benefits Earned by Employees	18	16	15
Interest Cost on Benefits Earned	13	12	12
Actual Return on Plan Assets	(18)	(23)	(18)
Actuarial (Gains)/Losses	(2)	9	33
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	11	14	42
Difference Between Actual and Expected Return on Plan Assets	5	12	8
Difference Between Actual and Recognized Actuarial Losses	3	(7)	(32)
Difference Between Actual and Recognized Past Service Costs	1	1	–
Net Pension Expense	**20**	**20**	**18**
Canexus			
Cost of Benefits Earned by Employees	3	3	1
Interest Cost on Benefits Earned	3	3	1
Actual Return on Plan Assets	(2)	(6)	–
Actuarial (Gains)/Losses	(3)	2	(2)
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	1	2	–
Difference Between Actual and Expected Return on Plan Assets	(1)	3	(1)
Difference Between Actual and Recognized Actuarial Gains	3	(2)	2
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	**3**	**3**	**1**
Syncrude			
Cost of Benefits Earned by Employees	5	5	4
Interest Cost on Benefits Earned	6	5	5
Actual Return on Plan Assets	(2)	(8)	(6)
Actuarial Losses	1	–	11
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	10	2	14
Difference Between Actual and Expected Return on Plan Assets	(4)	3	2
Difference Between Actual and Recognized Actuarial Losses	1	2	(8)
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	**7**	**7**	**8**
Total Net Pension Expense	**30**	**30**	**27**

(b) Plan asset allocation at December 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committees of Nexen and Canexus. Nexen's and Canexus' investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's investment policies.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

(%)	Expected 2008	2007	2006
Nexen			
Equity Securities	64	64	60
Debt Securities	36	36	40
Total	**100**	**100**	**100**
Canexus			
Equity Securities	50	50	60
Debt Securities	50	50	40
Total	**100**	**100**	**100**
Syncrude			
Equity Securities	68	68	70
Debt Securities	32	32	30
Total	**100**	**100**	**100**

(c) Defined contribution pension plans

Under these plans, pension benefits are based on plan contributions. During 2007, Canadian pension expense for these plans was $6 million (2006—$4 million; 2005—$4 million). During 2007, US pension expense for these plans was $4 million (2006—$4 million; 2005—$4 million). During 2007, UK pension expense for these plans was $5 million (2006—$4 million; 2005—$2 million).

(d) Post-retirement benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded. The present value of Nexen employees' future post retirement benefits at December 31, 2007 was $10 million (2006—$6 million) and $1 million for Canexus (2006—$2 million).

(e) Employer funding contributions and benefit payments

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we make contributions on behalf of our employees and no further obligation exists. Our funding contributions for the defined benefit plans are:

Defined Benefit Contributions	Expected 2008	2007	2006
Nexen	11	6	24
Canexus	1	3	3
Syncrude	7	6	5
Total Funding Contributions	**19**	**15**	**32**

Our most recent funding valuation was prepared as of June 30, 2007. Our next funding valuation is required by June 30, 2010. Canexus' most recent funding valuation was prepared as of December 31, 2007, and their next funding valuation is required by December 31, 2010. Syncrude's most recent funding valuation was prepared as of December 31, 2007, and their next funding valuation is December 31, 2009.

Our total benefit payments in 2007 were $13 million for Nexen (2006—$11 million). Our share of Syncrude's total benefit payments in 2007 was $4 million (2006—$4 million). Our estimated future payments are as follows:

	Defined Benefit			Other		
	Nexen	Canexus	Syncrude	Nexen	Canexus	Syncrude
2008	9	1	4	2	–	–
2009	10	1	4	2	–	–
2010	11	1	4	2	–	–
2011	12	2	5	3	–	–
2012	13	2	5	3	–	1
2013-2017	80	17	34	22	–	1

17. MARKETING AND OTHER INCOME

	2007	2006	2005
Marketing Revenue, Net	959	1,309	847
Business Interruption Insurance Proceeds [1]	–	154	2
Change in Fair Value of Crude Oil Put Options (Note 7b)	(43)	(11)	(196)
Interest	39	36	29
Foreign Exchange Losses	(22)	(72)	(19)
Gains on Disposition of Assets [2]	2	4	4
Other	86	30	35
Total Marketing and Other	**1,021**	**1,450**	**702**

Notes.

1 *In 2006, we received business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005 and by generator failures in our UK operations in 2005.*

2 *Gains on disposition of assets resulted from the sale of minor oil and gas assets in our Canadian operations in 2007 and 2006; and from the sale of our Ejulebe assets, offshore Nigeria in 2005.*

18. INCOME TAXES

(a) Temporary differences

	2007		2006	
	Future Income Tax Assets [1]	Future Income Tax Liabilities	Future Income Tax Assets [1]	Future Income Tax Liabilities
Property, Plant and Equipment, Net	25	2,229	26	2,420
Tax Losses Carried Forward	256	–	594	–
Deferred Income	–	61	–	48
Recoverable Taxes	5	–	–	–
Total	**286**	**2,290**	**620**	**2,468**

Note:

1 *Future income tax assets of $18 million (2006—$479 million) that we expect to realize in the following twelve months have been included in current assets.*

(b) Canadian and foreign income taxes

	2007	2006	2005
Income (Loss) from Continuing Operations before Income Taxes			
Canadian	(33)	(352)	(396)
Foreign	1,929	1,648	1,326
	1,896	1,296	930
Provision for Income Taxes			
Current			
Canadian	1	14	1
Foreign	433	354	338
	434	368	339
Future			
Canadian	12	(96)	(206)
Foreign	346	411	101
	358	315	(105)
Total Provision for Income Taxes	**792**	**683**	**234**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, Colombia, the United Kingdom and the United States.

(c) Reconciliation of effective tax rate to the Canadian statutory tax rate

	2007	2006	2005
Income from Continuing Operations before Income Taxes	1,896	1,296	930
Provision for Income Taxes Computed at the Canadian Statutory Rate	537	401	318
Add (Deduct) the Tax Effect of:			
Royalties, Rentals and Similar Payments to Provincial Governments	–	15	24
Resource Allowance and Provincial Tax Rebates	–	(15)	(24)
Foreign Tax Rate Differential	233	(9)	(40)
Additional Canadian Tax on Canadian Resource Income	–	10	6
Lower Tax Rates on Capital Gains	(5)	(3)	(54)
Federal and Provincial Capital Tax	1	13	5
Effect of Changes in Tax Rates	(15)	245	–
Non-Deductible Expenses and Other	41	26	(1)
Provision for Income Taxes	**792**	**683**	**234**
Effective Tax Rate	**42%**	**53%**	**25%**

During the first quarter of 2006, we recorded a future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom. The United Kingdom parliament increased the supplemental tax rate from 10% to 20%, effective January 1, 2006.

In 2007 and 2006, the federal and some provincial governments in Canada reduced statutory corporate income tax rates. This reduced our liability and provision for future income taxes by $15 million in 2007 (2006—$32 million).

(d) Available unused tax losses and tax contingencies

At December 31, 2007, we had unused tax losses totalling $820 million (2006—$1,258 million; 2005—$965 million). The majority of these losses are from Canada and the US and will expire between 2015 and 2027.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an adequate provision for income taxes based on available information.

19. CASH FLOWS

(a) Charges and credits to income not involving cash

	2007	2006	2005
Depreciation, Depletion, Amortization and Impairment	1,767	1,124	1,052
Stock-Based Compensation	(109)	101	428
Gains on Disposition of Assets	(2)	(4)	(4)
Provision for Future Income Taxes	358	315	(105)
Change in Fair Value of Crude Oil Put Options	43	11	196
Non-Cash Items included in Discontinued Operations	–	–	(325)
Gain on Dilution of Interest in Chemicals Business	–	–	(193)
Net Income Attributable to Non-Controlling Interests	18	12	8
Other	(2)	70	24
Total	**2,073**	**1,629**	**1,081**

(b) Changes in non-cash working capital

	2007	2006	2005
Accounts Receivable	(797)	345	(1,078)
Inventories and Supplies	(97)	(302)	(163)
Other Current Assets	(15)	(14)	(10)
Accounts Payable and Accrued Liabilities	691	(72)	982
Other	–	–	20
Total	**(218)**	**(43)**	**(249)**
Relating to:			
Operating Activities	(348)	(177)	(195)
Investing Activities	130	134	(54)
Total	**(218)**	**(43)**	**(249)**

(c) Other cash flow information

	2007	2006	2005
Interest Paid	328	278	237
Income Taxes Paid	408	398	325

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $123 million (2006—$128 million; 2005—$53 million).

20. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in Colombia, West Africa and Norway.

Energy Marketing: Our marketing group sells our crude oil and natural gas, markets third-party crude oil, natural gas, NGL's, ethanol and power and engages in energy trading, including electricity generation.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from mining bitumen in the oil sands in northern Alberta.

Chemicals: Through our investment in Canexus LP, we manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. We produce sodium chlorate at four facilities in Canada and one in Brazil. We produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses with the exception of Chemicals. Identifiable assets are those used in the operations of the segments.

2007 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	US	UK	Other Countries[1]					
Net Sales[2]	1,086	441	616	2,285	148	48	545	414[3]	–	5,583
Marketing and Other	10	6	–	39	–	959	–	33	(26)[4]	1,021
	1,096	447	616	2,324	148	1,007	545	447	(26)	6,604
Less: Expenses										
Operating	171	173	102	212	8	34	208	257	–	1,165
Depreciation, Depletion, Amortization and Impairment	213	166	641[5]	599	8	13	53	45	29	1,767
Transportation and Other	8	22	–	–	–	806	17	39	16	908
General and Administrative[6]	(6)	50	38	3	40	87	1	31	130	374
Exploration	5	27	134	69	91[7]	–	–	–	–	326
Interest	–	–	–	–	–	–	–	11	157	168
Income (Loss) from Continuing Operations before Income Taxes	705	9	(299)	1,441	1	67	266	64	(358)	1,896
Less: Provision for (Recovery of) Income Taxes[8]	248	3	(103)	712	–	21	75	18	(182)	792
Net Income (Loss) from Continuing Operations	457	6	(196)	729	1	46	191	46	(176)	1,104
Less: Non-Controlling Interests	–	–	–	–	–	–	–	18	–	18
Net Income (Loss)	**457**	**6**	**(196)**	**729**	**1**	**46**	**191**	**28**	**(176)**	**1,086**
Identifiable Assets	**359**	**5,379[9]**	**1,640**	**4,642**	**317**	**3,663[10]**	**1,212**	**487**	**376**	**18,075**
Capital Expenditures										
Development and Other	124	1,381	414	551	53	4	36	62	52	2,677
Exploration	12	123	275	119	44	–	–	–	–	573
Proved Property Acquisitions	–	1	104[11]	46[12]	–	–	–	–	–	151
Total Capital Expenditures	**136**	**1,505**	**793**	**716**	**97**	**4**	**36**	**62**	**52**	**3,401**
Property, Plant and Equipment										
Cost	2,178	6,736	3,069	4,723	263	246	1,332	831	315	19,693
Less: Accumulated DD&A	1,950	1,597	1,765	908	77	62	205	463	168	7,195
Net Book Value[2]	**228**	**5,139[9]**	**1,304**	**3,815**	**186**	**184**	**1,127**	**368**	**147**	**12,498**
Goodwill	**–**	**–**	**–**	**276**	**–**	**50**	**–**	**–**	**–**	**326**

Notes:

1 Includes results of operations from producing activities in Colombia.

2 Net sales made from all segments originating in Canada: 1,188
PP&E located in Canada: 6,893

3 Net sales for our chemicals operations include:

Canada	*154*
United States	*169*
Brazil	*91*
Total	***414***

4 Includes interest income of $39 million, foreign exchange losses of $22 million and decrease in the fair value of crude oil put options of $43 million.

5 Includes an impairment charge of $366 million related to oil and gas properties in the Gulf of Mexico.

6 Includes stock-based compensation expense of $38 million.

7 Includes exploration activities primarily in Nigeria, Norway and Colombia.

8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

9 Includes costs of $3,695 million related to our Long Lake Project (Phase 1 and future phases).

10 Approximately 84% of Marketing's identifiable assets are accounts receivable and inventories.

11 Includes acquisition of producing properties in the Gulf of Mexico.

12 Includes acquisition of additional interests in the Scott and Telford fields.

2006 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	US	UK	Other Countries[1]					
Net Sales[2]	1,328	459	629	477	139	51	446	407[3]	–	3,936
Marketing and Other	8	7	81[4]	85[5]	1	1,309	–	6	(47)[6]	1,450
	1,336	466	710	562	140	1,360	446	413	(47)	5,386
Less: Expenses										
Operating	151	143	106	80	8	31	187	249	–	955
Depreciation, Depletion, Amortization and Impairment[7]	327	162	296	216	10	12	33	40	28	1,124
Transportation and Other	6	33	–	–	1	789	18	40	154[8]	1,041
General and Administrative[9]	17	80	58	14	44	112	1	29	200	555
Exploration	4	26	214	46	72[10]	–	–	–	–	362
Interest	–	–	–	–	–	–	–	11	42	53
Income (Loss) from Continuing Operations before Income Taxes	831	22	36	206	5	416	207	44	(471)	1,296
Less: Provision for (Recovery of) Income Taxes[11]	289	7	13	378[12]	1	151	66	15	(237)	683
Net Income (Loss) from Continuing Operations	542	15	23	(172)	4	265	141	29	(234)	613
Less: Non-Controlling Interests	–	–	–	–	–	–	–	12	–	12
Net Income (Loss)	**542**	**15**	**23**	**(172)**	**4**	**265**	**141**	**17**	**(234)**	**601**
Identifiable Assets	**464**	**3,923**[13]	**1,620**	**5,490**	**245**	**3,528**[14]	**1,186**	**459**	**241**	**17,156**
Capital Expenditures										
Development and Other	145	1,434	418	596	28	47	86	27	45	2,826
Exploration	37	163	177	62	52	–	–	–	–	491
Proved Property Acquisitions	–	12	–	1	–	–	–	–	–	13
Total Capital Expenditures	**182**	**1,609**	**595**	**659**	**80**	**47**	**86**	**27**	**45**	**3,330**
Property, Plant and Equipment										
Cost	2,404	5,216	2,889	4,710	249	226	1,304	854	286	18,138
Less: Accumulated DD&A	2,128	1,448	1,445	432	78	47	179	494	148	6,399
Net Book Value[2]	**276**	**3,768**[13]	**1,444**	**4,278**	**171**	**179**	**1,125**	**360**	**138**	**11,739**
Goodwill	–	–	–	**325**	–	**52**	–	–	–	**377**

Notes:

1 Includes results of operations from producing activities in Colombia.

2 Net sales made from all segments originating in Canada: 1,095
PP&E located in Canada: 5,483

3 Net sales for our chemicals operations include:

Canada	*139*
United States	*185*
Brazil	*83*
Total	***407***

4 Includes $80 million of business interruption insurance proceeds related to production losses caused by Gulf of Mexico hurricanes in 2005.

5 Includes $74 million of business interruption insurance proceeds for generator failures in 2005.

6 Includes interest income of $36 million, foreign exchange losses of $72 million and decrease in the fair value of crude oil put options of $11 million.

7 Includes an impairment charge of $93 million, primarily relating to two natural gas properties in the Gulf of Mexico.

8 Includes $151 million (US$135 million) accrual with respect to the Block 51 arbitration settlement.

9 Includes stock-based compensation expense of $210 million.

10 Includes exploration activities primarily in Nigeria, Norway and Colombia.

11 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

12 Includes future income tax expense of $277 million related to an increase in the supplemental tax rate on oil and gas activities in the United Kingdom (see Note 18).

13 Includes costs of $2,444 million related to our Long Lake Project (Phase 1 and future phases).

14 Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.

2005 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas					Energy Marketing	Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada[1]	US	UK	Other Countries[2]					
Net Sales[3]	1,377	455	792	366	119	28	397	398[4]	–	3,932
Marketing and Other	8	3	2	16	4	847	–	15	(193)[5]	702
Gain on Dilution of Interest in Chemicals Business	–	–	–	–	–	–	–	193	–	193
	1,385	458	794	382	123	875	397	606	(193)	4,827
Less: Expenses										
Operating	150	121	96	95	12	30	152	237	–	893
Depreciation, Depletion, Amortization and Impairment	354	140	234	210	13	11	17	51[6]	22	1,052
Transportation and Other	6	23	1	–	2	641	21	40	62	796
General and Administrative[7]	42	107	88	8	101	89	1	45	328	809
Exploration	12	23	100	51	64[8]	–	–	–	–	250
Interest	–	–	–	–	–	–	–	3	94	97
Income (Loss) from Continuing Operations before Income Taxes	821	44	275	18	(69)	104	206	230	(699)	930
Less: Provision for (Recovery of) Income Taxes[9]	285	13	98	7	(13)	41	60	15	(272)	234
Net Income (Loss) from Continuing Operations	536	31	177	11	(56)	63	146	215	(427)	696
Less: Non-Controlling Interests	–	–	–	–	–	–	–	8	–	8
Add: Net Income from Discontinued Operations	–	452	–	–	–	–	–	–	–	452
Net Income (Loss)	**536**	**483**	**177**	**11**	**(56)**	**63**	**146**	**207**	**(427)**	**1,140**
Identifiable Assets	**635**	**2,449**[10]	**1,433**	**4,775**	**183**	**3,165**[11]	**1,135**	**482**	**333**	**14,590**
Capital Expenditures										
Development and Other	236	947	148	566	14	16	197	14	24	2,162
Exploration	41	90	211	59	55	–	–	–	–	456
Proved Property Acquisitions	–	17	3	–	–	–	–	–	–	20
Total Capital Expenditures	**277**	**1,054**	**362**	**625**	**69**	**16**	**197**	**14**	**24**	**2,638**
Property, Plant and Equipment Cost	2,243	3,631	2,437	4,013	249	177	1,240	827	245	15,062
Less: Accumulated DD&A	1,841	1,311	1,159	216	119	72	171	456	123	5,468
Net Book Value[3]	**402**	**2,320**[10]	**1,278**	**3,797**	**130**	**105**	**1,069**	**371**	**122**	**9,594**
Goodwill	–	–	–	**325**	–	**39**	–	–	–	**364**

Notes:

1 During the third quarter of 2005, we concluded the sale of Canadian conventional oil and gas properties. The results of these properties are shown as discontinued operations (see Note 14).

2 Includes results of operations from producing activities in Nigeria and Colombia.

3 Net sales made from all segments originating in Canada: 1,014
PP&E located in Canada: 3,899

4 Net sales for our chemicals operations include:

Canada	*132*
United States	*198*
Brazil	*68*
Total	***398***

5 Includes interest income of $29 million, foreign exchange losses of $19 million, decrease in the fair value of crude oil put options of $196 million and decrease in the fair value of foreign currency call options of $7 million.

6 Includes impairment charge of $12 million related to the closure of our sodium chlorate plant in Amherstburg, Ontario.

7 Includes stock-based compensation expense of $507 million.

8 Includes exploration activities primarily in Nigeria, Colombia and Equatorial Guinea.

9 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

10 Includes costs of $1,321 million related to our Long Lake Project (Phase 1 and future phases).

11 Approximately 86% of Marketing's identifiable assets are accounts receivable and inventories.

21. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP
For the Three Years ended December 31, 2007

(Cdn$ millions, except per share amounts)	2007	2006	2005
Revenues and Other Income			
Net Sales	5,583	3,936	3,932
Marketing and Other (ii); (vii); (viii)	938	1,459	687
Gain on Dilution of Interest in Chemicals Business	–	–	193
	6,521	5,395	4,812
Expenses			
Operating (iii)	1,167	958	903
Depreciation, Depletion, Amortization and Impairment (i)	1,767	1,124	1,081
Transportation and Other (vii)	906	1,037	792
General and Administrative (vi)	401	597	792
Exploration	326	362	250
Interest	168	53	97
	4,735	4,131	3,915
Income from Continuing Operations before Income Taxes	1,786	1,264	897
Provision for Income Taxes			
Current	434	368	339
Deferred (ii) – (viii)	322	305	(108)
	756	673	231
Net Income from Continuing Operations before Non-Controlling Interests	1,030	591	666
Net Income Attributable to Non-Controlling Interests	18	12	8
Net Income from Continuing Operations	1,012	579	658
Net Income from Discontinued Operations	–	–	452
Net Income—US GAAP [1]	**1,012**	**579**	**1,110**
Earnings Per Common Share ($/share)			
Basic (Note 13)			
Net Income from Continuing Operations	1.92	1.10	1.26
Net Income from Discontinued Operations	–	–	0.87
	1.92	1.10	2.13
Diluted (Note 13)			
Net Income from Continuing Operations	1.88	1.08	1.23
Net Income from Discontinued Operations	–	–	0.85
	1.88	**1.08**	**2.08**

Note:

1 Reconciliation of Canadian and US GAAP Net Income

(Cdn$ millions)	*2007*	*2006*	*2005*
Net Income—Canadian GAAP	*1,086*	*601*	*1,140*
Impact of US Principles, Net of Income Taxes:			
Ineffective Portion of Cash Flow Hedges (ii)	*(2)*	*9*	*(7)*
Depreciation, Depletion, Amortization and Impairment (i)	*–*	*–*	*(29)*
Pre-operating Costs (iii)	*(1)*	*(2)*	*(6)*
Stock-based Compensation (vi)	*(19)*	*(29)*	*12*
Inventory Valuation (viii)	*(52)*	*–*	*–*
Net Income—US GAAP	***1,012***	***579***	***1,110***

Consolidated Balance Sheet—US GAAP
December 31, 2007 and 2006

(Cdn$ millions, except share amounts)	2007	2006
ASSETS		
Current Assets		
Cash and Cash Equivalents	206	101
Restricted Cash and Margin Deposits	203	197
Accounts Receivable (ii)	3,502	2,976
Inventories and Supplies (viii)	615	786
Deferred Income Tax Assets	18	479
Other	71	67
Total Current Assets	4,615	4,606
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $7,588 (December 31, 2006—$6,792) (iii); (v)	12,449	11,692
Goodwill	326	377
Deferred Income Tax Assets	268	141
Deferred Charges and Other Assets	324	263
TOTAL ASSETS	**17,982**	**17,079**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings	–	158
Accounts Payable and Accrued Liabilities (ii); (vi)	4,233	3,839
Accrued Interest Payable	54	55
Dividends Payable	13	13
Total Current Liabilities	4,300	4,065
Long-Term Debt	4,610	4,618
Deferred Income Tax Liabilities (i) – (viii)	2,230	2,427
Asset Retirement Obligations	792	683
Deferred Credits and Other Liabilities (iv)	534	597
Non-Controlling Interests	67	75
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2007—528,304,813 shares		
2006—525,026,412 shares	917	821
Contributed Surplus	3	4
Retained Earnings (i) – (viii)	4,876	3,945
Accumulated Other Comprehensive Loss (ii); (iv)	(347)	(156)
Total Shareholders' Equity	5,449	4,614
Commitments, Contingencies and Guarantees		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**17,982**	**17,079**

Consolidated Statement of Comprehensive Income—US GAAP
For the Three Years ended December 31, 2007

(Cdn$ millions)	2007	2006	2005
Net Income—US GAAP	1,012	579	1,110
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment	(132)	–	(56)
Change in Mark to Market on Cash Flow Hedges (ii)	(61)	77	(20)
Minimum Unfunded Pension Liability (iv)	–	5	(10)
Unamortized Defined Benefit Pension Plan Costs (iv)	2	–	–
Comprehensive Income	**821**	**661**	**1,024**

Consolidated Statement of Accumulated Other Comprehensive Loss—US GAAP
December 31, 2007 and 2006

(Cdn$ millions)	2007	2006
Foreign Currency Translation Adjustment	(293)	(161)
Mark to Market on Cash Flow Hedges (ii)	–	61
Unamortized Defined Benefit Pension Plan Costs (iv)	(54)	(56)
Accumulated Other Comprehensive Loss (AOCI)	**(347)**	**(156)**

Notes to the Consolidated US GAAP Financial Statements:

i. Under US GAAP, the liability method of accounting for income taxes was adopted in 1993. In Canada, the liability method was adopted in 2000. In 1997, we acquired certain oil and gas assets and the amount paid for these assets differed from the tax basis acquired. Under US principles, this difference was recorded as a deferred tax liability with an increase to PP&E rather than a charge to retained earnings. As a result, additional depreciation, depletion, amortization and impairment of $29 million was included in net income during 2005. The difference was fully amortized during 2005.

ii. Under US GAAP, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. On January 1, 2007, we adopted the equivalent Canadian standard for derivative instruments and hedging (see note 1(u)).

Future sale of gas inventory:

We use futures and swaps as cash flow hedges against the commodity price risk on the future sale of our gas inventory. Prior to January 1, 2007, we included the hedging derivative contracts on our US GAAP Consolidated Balance Sheet with the effective portion of gains or losses recognized in AOCI. The ineffective gain or loss is included in marketing and other on the US GAAP net income immediately.

In 2005, we recognized $11 million ($7 million, net of income taxes) of ineffective losses related to these hedges in our US GAAP net income. Under Canadian GAAP, these losses were recognized in 2006.

At December 31, 2006, we included $25 million of gains on these cash flow hedges in accounts receivable. AOCI includes the effective portion of $23 million ($16 million, net of income taxes) and $2 million ($2 million, net of income taxes) of the ineffective portion in our US GAAP net income. Under Canadian GAAP, these gains were recognized in 2007.

Under US GAAP, AOCI included gains of $65 million ($45 million, net of income taxes) at December 31, 2006 related to de-designated cash flow hedges as described in Note 7(b). These gains were recognized in marketing and other in the first quarter of 2007. Under Canadian GAAP, these deferred gains were included in accounts payable and accrued liabilities at December 31, 2006 and were recognized in marketing and other in the first quarter of 2007.

iii. Under Canadian GAAP, we defer certain development costs and all pre-operating revenues and costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:

- operating expenses include pre-operating costs of $2 million ($1 million, net of income taxes) (2006—$3 million ($2 million, net of income taxes); 2005—$10 million ($6 million, net of income taxes)); and
- PP&E is lower under US GAAP by $30 million (December 31, 2006—$28 million).

iv. On December 31, 2006, we adopted FASB Statement No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* for US GAAP. This requires, among other things, the recognition of the over-funded and under-funded status of a defined benefit plan on the balance sheet as an asset or liability.

At year end, the unfunded amount of our defined benefit pension plans was $75 million (2006—$81 million). This amount has been included in deferred credits and other liabilities and $54 million, net of income taxes, (2006—$56 million, net of income taxes), has been included in AOCI. Prior to the adoption of FAS 158 on December 31, 2006, we included our minimum unfunded pension liability in our US GAAP Consolidated Balance Sheet. This liability decreased by $5 million in 2006 and increased $10 million in 2005.

v. On January 1, 2003, we adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

vi. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. In addition, under Canadian principles, we retroactively adopted EIC–162 which requires the accelerated recognition of stock-based compensation expense for all stock-based awards made to our retired and retirement-eligible employees. However, US GAAP requires the accelerated recognition of stock-based compensation expense for such employees for awards granted on or after January 1, 2006. As a result:
   - general and administrative expense is higher by $27 million ($19 million, net of income taxes) for the year ended December 31, 2007 (2006—higher by $42 million ($29 million, net of income taxes); 2005—lower by $17 million ($12 million, net of income taxes)); and
   - accounts payable and accrued liabilities are higher by $53 million at December 31, 2007 (2006—higher by $25 million).

vii. Under US GAAP, asset disposition gains and losses are included with transportation and other expense. Gains of $2 million were reclassified from marketing and other to transportation and other (2006—$4 million; 2005—$4 million).

viii. Under Canadian GAAP, we began carrying our commodity inventory held for trading purposes at fair value, less any costs to sell effective October 1, 2007 (see Note 1(u)). Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result:
   - marketing and other is lower by $79 million ($52 million, net of income taxes) for the year ended December 31, 2007; and
   - inventories are lower by $44 million at December 31, 2007.

Stock-Based Compensation

On January 1, 2006, we adopted FASB Statement 123 (revised), *Share-Based Payment* (Statement 123(R)) using the modified prospective approach and graded vesting amortization. Under Statement 123(R), our tandem options and stock appreciation rights (StARS) are considered liability-based stock compensation plans. Under the modified prospective approach, no amounts are restated in prior periods. Upon adoption of Statement 123(R), we recorded a cumulative effect of a change in accounting principle of $2 million. This amount was recorded in general and administrative expenses in our US GAAP Consolidated Statement of Income in 2006.

Prior to the adoption of Statement 123(R), we accounted for our liability-based stock compensation plans in accordance with FASB Interpretation 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans* (the intrinsic-value method). Accordingly, obligations were accrued on a graded vesting basis and represented the difference between the market value of our common shares and the exercise price of underlying options and rights. Under Statement 123(R), obligations for liability-based stock compensation plans are measured at their fair value and remeasured in each subsequent reporting period.

Consistent with Statement 123(R), we account for any stock options that do not include a cash feature (equity-based stock compensation plans) using the fair-value method.

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of our stock-based compensation, with the following assumptions:

Expected Annual Dividends per Common Share ($/share)	0.10
Expected Volatility	31%
Risk-Free Interest Rate	4.2% – 4.5%
Weighted-Average Expected Life of Compensation Instruments (in years)	2.8 – 3.0

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the implied volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds. Our valuation methodology and assumptions are consistent with those previously used under FAS 123.

Stock Options

	Number (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/option)
Outstanding at December 31, 2007	27,403	20	2.9	325	13
Outstanding at December 31, 2007 and Expected to Vest	27,263	20	2.9	320	14
Exercisable at December 31, 2007	18,216	16	2.3	295	16

The total intrinsic value of stock options exercised during the year ended December 31, 2007 was $149 million (2006—$109 million; 2005—$83 million). As at December 31, 2007, we had $51 million of unrecognized compensation expense related to stock options which we expect to recognize over a weighted-average period of 1.5 years.

Stock Appreciation Rights

	Number (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/right)
Outstanding at December 31, 2007	15,435	24	3.3	122	11
Outstanding at December 31, 2007 and Expected to Vest	15,052	24	3.3	120	11
Exercisable at December 31, 2007	7,525	19	2.3	100	14

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2007 was $50 million (2006—$46 million; 2005—$34 million). As at December 31, 2007, we had $45 million of unrecognized compensation expense related to stock appreciation rights which we expect to recognize over a weighted-average period of 1.6 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2007, stock-based compensation expense of $65 million (2006—$252 million; 2005—$490 million) was included in general and administrative expense in the Consolidated Statement of Income—US GAAP.

For the year ended December 31, 2007, cash proceeds of $24 million were received related to the exercise of stock options (2006—$16 million; 2005—$29 million). For the year ended December 31, 2007, $149 million was paid related to the exercise of stock options and stock appreciation rights (2006—$119 million; 2005—$74 million). The income tax benefit recorded from the exercise of stock options and stock appreciation rights was $42 million (2006—$37 million; 2005—$24 million) for the period.

Stock Based Compensation Expense for Retired and Retirement Eligible Employees

We recognize stock-based compensation expense for our retired and retirement-eligible employees over an accelerated graded vesting period in accordance with the provisions of Statement 123(R) for stock-based awards granted to employees on or after January 1, 2006. For stock-based awards granted prior to the adoption of Statement 123(R), stock-based compensation expense for our retired and retirement-eligible employees is recognized over a graded vesting period. If we applied the accelerated graded vesting provisions of Statement 123(R) to stock-based awards granted to our retired and retirement-eligible employees prior to the adoption of Statement 123(R), our stock-based compensation expense would decrease by $9 million for the year ended December 31, 2007 (2006—decrease by $10 million; 2005—increase by $19 million).

Changes in Accounting Policies—US GAAP

Income Taxes

On January 1, 2007, we adopted FASB Interpretation 48 *Accounting for Uncertainty in Income Taxes* (FIN 48) regarding accounting and disclosure for uncertain tax positions. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the financial statements and prescribes how a company should recognize, measure, present and disclose uncertain tax positions that it has taken or expects to take on a tax return. The evaluation of tax positions under FIN 48 is a two-step process, whereby: (1) the company determines whether it is more-likely-than-not that the tax positions will be sustained based on the technical merits of the position; and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the company recognizes the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing

authority. On the adoption of FIN 48, we recorded a cumulative effect of a change in accounting principle of $28 million. This amount increased our deferred income tax liabilities and decreased our retained earnings as at January 1, 2007 in our US GAAP—Consolidated Balance Sheet.

As at December 31, 2007, the total amount of our unrecognized tax benefits was approximately $221 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Consolidated Statement of Income. As at December 31, 2007, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP—Consolidated Balance Sheet was approximately $9 million. We had no interest or penalties included in the US GAAP—Consolidated Statement of Income for the year ended December 31, 2007.

Our income tax filings are subject to audit by taxation authorities and as at December 31, 2007 the following tax years remained subject to examination; (i) Canada—1985 to date, (ii) United Kingdom—2002 to date and (iii) United States—2004 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next twelve months.

Reconciliation of Unrecognized Tax Benefits (Cdn$ millions)

Balance at January 1, 2007	210
Additions for tax positions related to the current year	10
Additions for tax positions related to prior years	33
Reductions for tax positions related to prior years	(32)
Balance at December 31, 2007	221

New Accounting Pronouncements—US GAAP

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement 157, *Fair Value Measurements*. Statement 157 defines fair value, establishes a framework for measuring fair value under US generally accepted accounting principles and expands disclosures about fair value measurements. For fiscal years beginning after November 15, 2007, companies will be required to implement the standard for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis in financial statements. However, a one year deferral for the implementation of Statement 157 is provided for other nonfinancial assets and liabilities. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

Effective December 31, 2006, we adopted the recognition and disclosure provisions of FASB Statement 158, *Employers' Accounting For Defined Benefit Pension And Other Postretirement Plans*. This statement also requires measurement of the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. We do not expect the adoption of the change in measurement date in 2008 to have a material impact on our results of operations or financial position.

In February 2007, FASB issued Statement 159, *The Fair Value Option For Financial Assets and Financial Liabilities*. The statement allows for the elective measurement of eligible financial instruments and certain other items at fair value in order to mitigate volatility in reported earnings without having to apply complex and detailed hedge accounting rules. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 141(revised), *Business Combinations*. Statement 141(revised) establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Noncontrolling Interests In Consolidated Financial Statements, an amendment of ARB. No 51*. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Quarterly Financial Data in Accordance with Canadian and US GAAP

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	2007	2006	2007	2006	2007	2006	2007	2006
Net Sales	1,140	980	1,399	1,039	1,446	997	1,598	920
Income (Loss) before Income Taxes is Comprised of:								
Oil and Gas [1]	303	196	604	476	642	372	308	56
Energy Marketing	(4)	166	70	69	(4)	42	5	139
Syncrude	54	20	48	59	88	77	76	51
Chemicals	11	12	21	22	25	10	7	–
Corporate and Other	(145)	(66)	(93)	(92)	(63)	(171)	(57)	(142)
	219	**328**	**650**	**534**	**688**	**330**	**339**	**104**
Net Income (Loss)—Canadian GAAP	**121**	**(83)**	**368**	**408**	**403**	**199**	**194**	**77**
US GAAP Adjustments	(3)	282	(14)	(11)	(15)	(283)	(42)	(10)
Net Income (Loss)—US GAAP	**118**	**199**	**354**	**397**	**388**	**(84)**	**152**	**67**
Earnings (Loss) per Common Share ($/share)								
Canadian GAAP—Basic	0.23	(0.16)	0.70	0.78	0.77	0.38	0.37	0.15
Canadian GAAP—Diluted	0.22	(0.16)	0.68	0.76	0.75	0.37	0.36	0.14
US GAAP—Basic	0.22	0.38	0.67	0.76	0.74	(0.16)	0.29	0.13
US GAAP—Diluted	0.22	0.37	0.66	0.74	0.72	(0.16)	0.28	0.12
Dividends Declared [2]	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Common Share Prices ($/share)								
Toronto Stock Exchange—High	37.60	34.05	36.51	34.75	36.32	35.61	32.63	32.90
Toronto Stock Exchange—Low	29.66	27.17	31.25	25.41	27.21	26.07	27.88	26.46
New York Stock Exchange—High (US$)	31.88	29.97	32.21	30.84	34.79	31.82	34.37	29.19
New York Stock Exchange—Low (US$)	25.18	23.49	29.08	22.82	25.25	23.35	27.58	23.45

Notes:

1 *The fourth quarter of 2007 includes an impairment charge of $366 million relating to oil and gas properties in the Gulf of Mexico. The fourth quarter of 2006 includes an impairment charge of $93 million, primarily relating to two natural gas properties in the Gulf of Mexico.*

2 *In February 2008, the Board of Directors declared a quarterly dividend of $0.025 per common share, payable April 1, 2008, to shareholders of record on March 10, 2008.*

3 *At December 31, 2007, there were 1,569 registered holders of common shares and 528,304,813 common shares outstanding.*

OIL AND GAS PRODUCING ACTIVITIES AND SYNCRUDE OPERATIONS (UNAUDITED)

The following oil and gas information is provided in accordance with the FASB Statement No. 69 *Disclosures about Oil and Gas Producing Activities*. It also includes information relating to our interest in Syncrude as it produces a crude oil product similar to our oil and gas activities even though these operations are considered mining activities under SEC regulations.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves for our conventional operations (excluding Syncrude) are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the reserves (including Syncrude) have been assessed by independent qualified reserves consultants.

Estimates of crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. See Critical Accounting Estimates in Item 7 for a description of our oil and gas and mining reserves estimation process.

	Total		Yemen[1]	Canada			United States		United Kingdom		Other Countries[3]
Conventional oil and bitumen are in mmbbls and natural gas is in bcf	Oil	Gas	Oil	Oil	Gas	Bitumen[2]	Oil	Gas	Oil	Gas	Oil
Proved Developed and Undeveloped Reserves[4]											
December 31, 2004	**351**	**600**	**80**	**79**	**372**	**–**	**52**	**215**	**128**	**13**	**12**
Extensions and Discoveries	15	111	5	4	47	–	1	57	5	7	–
Purchases of Reserves in Place	2	–	–	2	–	–	–	–	–	–	–
Sales of Reserves in Place	(28)	(80)	–	(28)	(80)	–	–	–	–	–	–
Revisions of Previous Estimates	9	(18)	(3)	2	3	–	(5)	(21)	15	–	–
Production	(45)	(81)	(23)	(9)	(37)	–	(7)	(36)	(5)	(8)	(1)
December 31, 2005	**304**	**532**	**59**	**50**	**305**	**–**	**41**	**215**	**143**	**12**	**11**
Extensions and Discoveries	52	89	1	1	54	–	2	26	23	9	25
Purchases of Reserves in Place	–	1	–	–	1	–	–	–	–	–	–
Sales of Reserves in Place	–	–	–	–	–	–	–	–	–	–	–
Revisions of Previous Estimates	231	(16)	(3)	3	(13)	219	(8)	(12)	19	9	1
Production	(38)	(74)	(19)	(6)	(33)	–	(5)	(34)	(6)	(7)	(2)
December 31, 2006	**549**	**532**	**38**	**48**	**314**	**219**	**30**	**195**	**179**	**23**	**35**
Extensions and Discoveries	13	51	1	1	31	–	1	18	10	2	–
Purchases of Reserves in Place	3	42	–	–	1	–	2	41	1	–	–
Sales of Reserves in Place	–	(10)	–	–	–	–	–	(10)	–	–	–
Revisions of Previous Estimates	53	(11)	(2)	3	7	15	(6)	(24)	43	6	–
Production	(57)	(72)	(14)	(5)	(35)	–	(6)	(31)	(30)	(6)	(2)
December 31, 2007	**561**	**532**	**23**	**47**	**318**	**234**	**21**	**189**	**203**	**25**	**33**
Proved Developed Reserves[5]											
December 31, 2005	154	438	46	44	275	–	37	161	17	2	10
December 31, 2006	286	460	33	44	287	40	28	161	131	12	10
December 31, 2007	**281**	**423**	**22**	**44**	**293**	**40**	**17**	**114**	**151**	**16**	**7**

Notes:

1 *Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.*

2 *Represents bitumen reserves from the insitu recovery of Canadian oil sands, rather than upgraded synthetic crude oil reserves to be sold.*

3 *Represents reserves in Nigeria and Colombia.*

4 *Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.*

5 *Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.*

Our net proved reserves and changes in those reserves for our Syncrude operations are disclosed below. Additional disclosures required by SEC Industry Guide 7 are on pages 22 and 23. The net proved reserves represent management's best estimate of proved synthetic reserves after royalties.

Estimates of Syncrude's synthetic crude oil reserves are based on detailed geological and engineering assessments of the bitumen volume in-place, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling density of less than 500 metres. In accordance with the approved mining plan, there are an estimated 1,780 million tons of economically extractable oil sands in the Base and North Mines, with an average bitumen grade of 10.6 weight percent. The Aurora North Mine contains an estimated 4,810 million tons of economically extractable oil sands at an average bitumen grade of 11.2 weight percent. Aurora South Lease 31 contains measured economically extractable oil sands of 4,309 million tons at an average bitumen grade of 10.8 weight percent.

	Synthetic Crude Oil		
(millions of barrels)	Base Mine and North Mine [1]	Aurora [2]	Total
December 31, 2004	**50**	**205**	**255**
Revision of Previous Estimates	–	(4)	(4)
Extensions and Discoveries	–	19	19
Production	(3)	(3)	(6)
December 31, 2005	**47**	**217**	**264**
Revision of Previous Estimates	1	4	5
Extensions and Discoveries	–	11	11
Production	(3)	(3)	(6)
December 31, 2006	**45**	**229**	**274**
Revision of Previous Estimates	–	(7)	(7)
Extensions and Discoveries	–	7	7
Production	(3)	(4)	(7)
December 31, 2007	**42**	**225**	**267**

Notes:
1 Leases 17 and 22
2 Leases 10, 12, 31 and 34.

B. Capitalized Costs (excluding Syncrude operations)

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
December 31, 2007				
Yemen	2,178	–	(1,950)	228
Canada	4,364	734	(1,990)	3,108
United States	2,931	138	(1,765)	1,304
United Kingdom	4,318	405	(908)	3,815
Other Countries	105	158	(77)	186
Total Capitalized Costs	**13,896**	**1,435**	**(6,690)**	**8,641**
December 31, 2006				
Yemen	2,404	–	(2,128)	276
Canada	3,787	227	(1,467)	2,547
United States	2,768	121	(1,445)	1,444
United Kingdom	4,325	385	(432)	4,278
Other Countries	99	150	(78)	171
Total Capitalized Costs	**13,383**	**883**	**(5,550)**	**8,716**
December 31, 2005				
Yemen	2,243	–	(1,841)	402
Canada	3,463	143	(1,330)	2,276
United States	2,323	114	(1,159)	1,278
United Kingdom	3,603	410	(216)	3,797
Other Countries	88	161	(119)	130
Total Capitalized Costs	**11,720**	**828**	**(4,665)**	**7,883**

C. Costs Incurred (excluding Syncrude operations)

		Oil and Gas				
(Cdn$ millions)	Total Oil and Gas	Yemen	Canada	United States	United Kingdom	Other
Year Ended December 31, 2007						
Property Acquisition Costs						
Proved	151	–	1	104	46	–
Unproved	59	–	34	24	1	–
Exploration Costs	637	15	93	311	128	90
Development Costs	1,817	124	675	414	551	53
Asset Retirement Costs	169	6	48	30	85	–
Total Costs Incurred	**2,833**	**145**	**851**	**883**	**811**	**143**
Year Ended December 31, 2006						
Property Acquisition Costs						
Proved	13	–	12	–	1	–
Unproved	125	–	105	19	1	–
Exploration Costs	514	37	74	242	71	90
Development Costs	2,051	145	884	399	595	28
Asset Retirement Costs	69	4	5	4	56	–
Total Costs Incurred	**2,772**	**186**	**1,080**	**664**	**724**	**118**
Year Ended December 31, 2005						
Property Acquisition Costs						
Proved	20	–	17	3	–	–
Unproved	15	–	–	9	6	–
Exploration Costs	509	44	97	235	61	72
Development Costs	1,896	236	947	139	560	14
Asset Retirement Costs	196	13	58	45	80	–
Total Costs Incurred	**2,636**	**293**	**1,119**	**431**	**707**	**86**

D. Results of Operations for Producing Activities (excluding Syncrude operations)

(Cdn$ millions)	Total Oil and Gas	Oil and Gas: Yemen	Canada[1]	United States	United Kingdom	Other Countries
Year Ended December 31, 2007						
Net Sales	4,576	1,086	441	616	2,285	148
Production Costs	668	171	175	102	212	8
Exploration Expense	326	5	27	134	69	91
Depreciation, Depletion, Amortization and Impairment	1,627	213	166	641	599	8
Other Expenses (Income)	100	(8)	66	38	(36)	40
	1,855	705	7	(299)	1,441	1
Income Tax Provision (Recovery)	859	248	2	(103)	712	–
Results of Operations	**996**	**457**	**5**	**(196)**	**729**	**1**
Year Ended December 31, 2006						
Net Sales	3,032	1,328	459	629	477	139
Production Costs	491	151	146	106	80	8
Exploration Expense	362	4	26	214	46	72
Depreciation, Depletion, Amortization and Impairment	1,011	327	162	296	216	10
Other Expenses (Income)	71	15	106	(23)	(71)	44
	1,097	831	19	36	206	5
Income Tax Provision	687	289	6	13	378	1
Results of Operations	**410**	**542**	**13**	**23**	**(172)**	**4**
Year Ended December 31, 2005						
Net Sales	3,263	1,377	609	792	366	119
Production Costs	511	150	158	96	95	12
Exploration Expense	251	12	24	100	51	64
Depreciation, Depletion, Amortization and Impairment	1,008	354	197	234	210	13
Other Expenses	335	40	125	83	(8)	95
	1,158	821	105	279	18	(65)
Income Tax Provision (Recovery)	411	285	32	99	7	(12)
Results of Operations	**747**	**536**	**73**	**180**	**11**	**(53)**

Note:
1 2005 includes results of discontinued operations (see Note 14).

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein (excluding Syncrude operations)

The following disclosure is based on estimates of net proved reserves (excluding Syncrude) and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved oil and gas reserves (excluding Syncrude operations). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	United Kingdom	Other Countries
December 31, 2007						
Future Cash Inflows	43,888	1,952	17,365	3,207	17,977	3,387
Future Production Costs	11,988	468	7,229	539	3,347	405
Future Development Costs	3,229	22	957	328	778	1,144
Future Dismantlement and Site Restoration Costs, Net	1,143	16	273	197	595	62
Future Income Tax	8,793	452	1,135	437	6,589	180
Future Net Cash Flows	18,735	994	7,771	1,706	6,668	1,596
10% Discount Factor	7,606	111	4,236	441	1,561	1,257
Standardized Measure	**11,129**	**883**	**3,535**	**1,265**	**5,107**	**339**
December 31, 2006						
Future Cash Inflows	32,247	2,330	12,678	3,151	11,437	2,651
Future Production Costs	9,523	606	5,615	791	2,236	275
Future Development Costs	3,190	115	1,156	332	891	696
Future Dismantlement and Site Restoration Costs, Net	1,006	11	289	197	471	38
Future Income Tax	5,204	489	753	450	3,308	204
Future Net Cash Flows	13,324	1,109	4,865	1,381	4,531	1,438
10% Discount Factor	4,951	106	2,484	321	970	1,070
Standardized Measure	**8,373**	**1,003**	**2,381**	**1,060**	**3,561**	**368**
December 31, 2005						
Future Cash Inflows	23,040	3,675	4,558	5,002	9,190	615
Future Production Costs	5,477	807	1,886	811	1,892	81
Future Development Costs	1,093	153	124	268	534	14
Future Dismantlement and Site Restoration Costs, Net	778	20	180	193	381	4
Future Income Tax	4,496	795	244	1,107	2,172	178
Future Net Cash Flows	11,196	1,900	2,124	2,623	4,211	338
10% Discount Factor	3,154	338	811	697	1,209	99
Standardized Measure	**8,042**	**1,562**	**1,313**	**1,926**	**3,002**	**239**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	2007	2006	2005
Beginning of Year	8,373	8,042	6,290
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(3,010)	(2,291)	(2,028)
Net Changes in Prices and Production Costs Related to Future Production	3,385	(1,065)	3,302
Extensions, Discoveries and Improved Recovery, Less Related Costs	758	695	977
Changes in Estimated Future Development and Dismantlement Costs	(443)	(692)	(135)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	1,102	1,048	638
Revisions of Previous Quantity Estimates	2,189	1,936	478
Accretion of Discount	1,191	1,117	799
Purchases of Reserves in Place	272	2	15
Sales of Reserves in Place	(49)	(2)	(882)
Net Change in Income Taxes	(2,639)	(417)	(1,412)
End of Year	**11,129**	**8,373**	**8,042**

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There were no disagreements with accountants on accounting and financial disclosure.

ITEM 9A. CONTROLS AND PROCEDURES EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-d-15(e)) as of the end of the period covered by this report. They concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Company and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2007. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report which is on page 126 of this Form 10-K and has issued an attestation report on our internal control over financial reporting.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems relative to internal controls over financial reporting. There have not been any changes in the Company's internal control over financial reporting during the last quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. As well, no material weaknesses requiring corrective action were identified in the conduct of our evaluation of internal control over financial reporting. As a result, no such corrective actions were taken.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:
We have audited the internal control over financial reporting of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

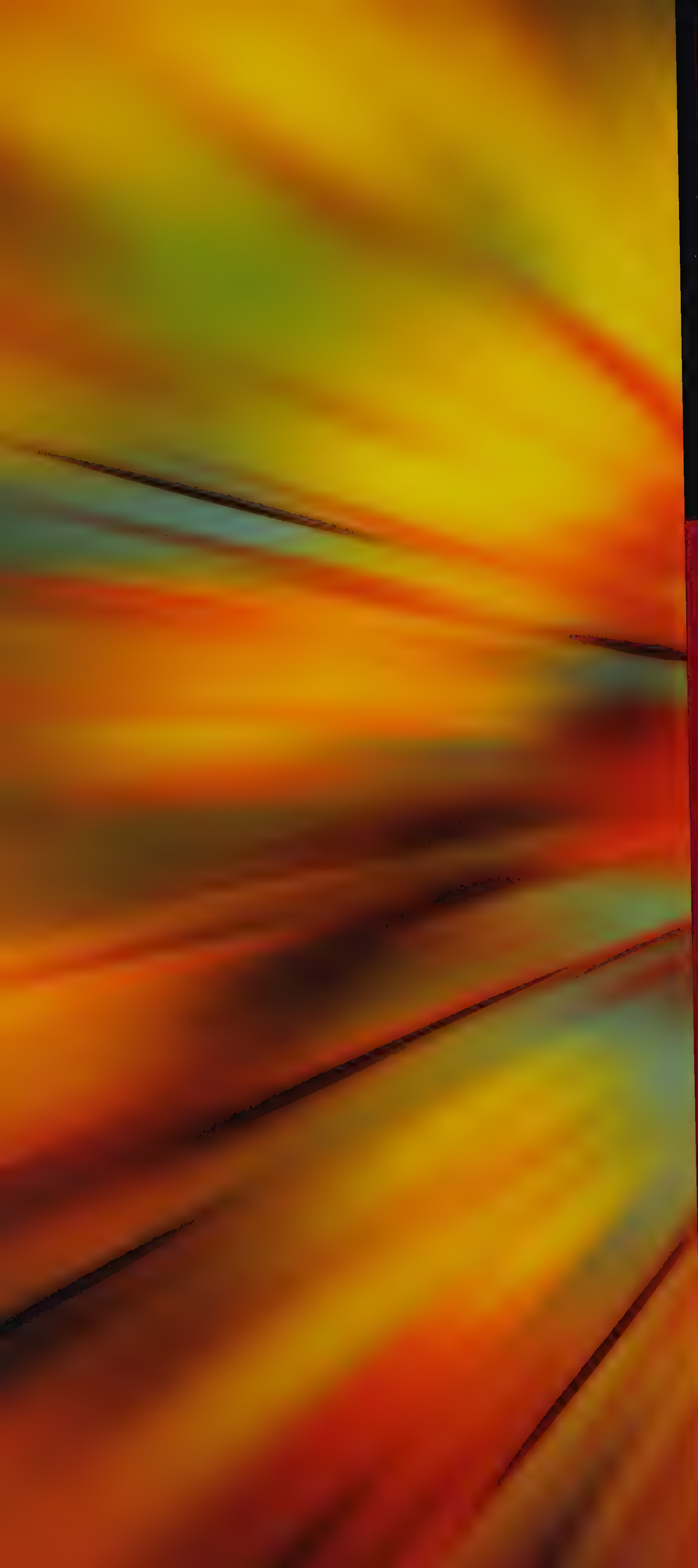
A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2007, and our report dated February 13, 2008, expressed an unqualified opinion on those financial statements and includes a separate report titled Comments by Independent Registered Chartered Accountants on Canada—United States of America Reporting Difference referring to changes in accounting principles that have a material effect on the comparability of the Company's financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 13, 2008



corporate **governance**

Recognized as a leader in corporate governance, we're committed to meaningful, transparent disclosure for all stakeholders.

PARTS III AND IV
ITEMS 10 TO 15.

PART III
Items 10 and 11. Directors, Executive Officers and Corporate Governance, and Executive Compensation

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On July 5, 2006, the board determined that, until changed, there will be 12 directors.

Our By-Laws provide that directors will be elected at the annual general meeting of shareowners (AGM) each year and will hold office until their successors are elected. All of our current directors were elected at the last AGM.

This shows our directors' principal occupations or employment during the past five years and any other directorships they held in public companies as at February 14, 2008. The following directors are management nominees for election to the board.

Name (Age)	**Principal Occupation**	**Other Directorships**	**Nexen Director Since**
Charles W. Fischer (57)	President and Chief Executive Officer (CEO) of Nexen.		2000
Dennis G. Flanagan [1,3] (68)	Retired oil executive.	Canexus Income Fund (Chair) NAL Oil & Gas Trust	2000
David A. Hentschel [4] (74)	Retired oil executive. Formerly: Oil and gas consultant.	Cimarex Energy Co.	1985
S. Barry Jackson [1] (55)	Retired oil executive. Formerly: Chair of Resolute Energy Inc. and Chair of Deer Creek Energy Limited.	Cordero Energy Inc. TransCanada Corporation (Chair) TransCanada PipeLines Limited (Chair)	2001
Kevin J. Jenkins [1,2] (51)	Managing Director of TriWest Capital Partners Formerly: President and CEO of The Westaim Corporation.		1996
A. Anne McLellan, P.C. [1] (57)	Counsel with Bennett Jones LLP, Barristers and Solicitors and Distinguished Scholar in Residence at the University of Alberta in the Institute for United States Policy Studies. Formerly: Member of Parliament for Edmonton Centre, Deputy Prime Minister, Minister of Public Safety and Emergency Preparedness and Minister of Health.	Agrium Inc. Cameco Corporation	2006
Eric P. Newell, O.C. (63)	Retired Chair and CEO of Syncrude Canada Ltd.		2004
Thomas C. O'Neill [1,2] (62)	Retired Chair of PwC Consulting. Formerly: CEO of PwC Consulting. Prior to that, COO of PricewaterhouseCoopers LLP, Global.	Adecco S.A. BCE Inc. Loblaw Companies Limited	2002
Francis M. Saville, Q.C. [1] (69)	Chair of Nexen. Counsel with Fraser Milner Casgrain LLP, Barristers and Solicitors. Formerly: Senior Partner and Vice Chair of Fraser Milner Casgrain LLP, Barristers and Solicitors.		1994
Richard M. Thomson, O.C. [1,2] (74)	Retired banking executive.	The Thomson Corporation	1997
John M. Willson [1] (68)	Retired mining executive.	Finning International Inc. Harry Winston Diamond Corporation Pan American Silver Corporation	1996
Victor J. Zaleschuk [5] (64)	Retired oil executive.	Agrium Inc. Cameco Corporation (Chair)	1997

Notes:

1 *All members of the Audit and Conduct Review (Audit), Corporate Governance and Nominating (Governance) and Compensation and Human Resources (Compensation) Committees are independent. All members of the Audit Committee are independent under additional regulations for audit committee members*

2 *Financial Experts on Nexen's Audit Committee.*

3 *Mr. Flanagan was a director of Elek-Tek Inc., a US public computer retailing company, that was subject to bankruptcy proceedings in 1998*

4 *Mr. Hentschel was Chair and CEO of Occidental Oil and Gas Corporation from 1997 to 1999 and President and CEO of Nexen from 1995 to 1997*

5 *Mr. Zaleschuk was President and CEO of Nexen from 1997 to 2001.*

Independence and Board Committees

The board affirmed director independence under our categorical standards for director independence (categorical standards), which are available at www.nexeninc.com. The categorical standards have been in place since 2003 and most recently amended on February 14, 2008. Our categorical standards meet or exceed the requirements set out in SEC rules and regulations, the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley), the NYSE rules, *National Policy 58-201—Corporate Governance Guidelines, Multilateral Instrument 52-110—Audit Committees*, and applicable provisions of *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities.*

Mr. Fischer is not independent as he is President and CEO.

Mr. Flanagan is not independent as his son is Senior Vice President, Engineering, of TriAxon Resources Ltd. (TriAxon). In 2006, TriAxon acquired a company that was party to contracts with a subsidiary of Nexen. Under one of the contracts, Nexen paid approximately $4.5 million to TriAxon between July and December 2006 for products purchased at market price. Accordingly, Mr. Flanagan is not technically independent as of July 1, 2007. Mr. Flanagan was not aware that the company acquired by TriAxon held contracts with Nexen. The board has determined that Mr. Flanagan's independence of mind has not been compromised by this transaction and accordingly, the board continues to include him in their meetings without management.

Ms. McLellan has been counsel with Bennett Jones LLP (BJ), Barristers and Solicitors, Edmonton, Alberta, since June 27, 2006. BJ provided legal services to us in each of the last five years. Ms. McLellan does not solicit or participate in those services and does not receive any portion of the fees we pay to BJ. She is independent under our categorical standards.

Mr. Saville was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta, until the end of January 2004. Since February 1, 2004, he has been counsel with the firm. FMC provided legal services to us in each of the last five years. Mr. Saville does not solicit or participate in those services and does not receive any portion of the fees we pay to FMC. He is independent under our categorical standards.

We have not had an executive committee of the board since July 11, 2000.

	Committees (Number of Members)					
	Audit [1,2] (6)	**Compensation** [1] (7)	**Governance** [1] (7)	**Finance** (6)	**Reserves** [3] (7)	**HSE & SR** (8)
Management Director—Not Independent						
Charles W. Fischer						
Outside Director—Not Independent						
Dennis G. Flanagan				√	√	√
Independent Outside Directors						
David A. Hentschel				√	√	√
S. Barry Jackson	√	√			√	Chair
Kevin J. Jenkins [4]	√	Chair	√			√
A. Anne McLellan, P.C.		√	√	√		√
Eric P. Newell, O.C.	√		√		√	√
Thomas C. O'Neill [4,5]	Chair	√	√		√	
Francis M. Saville, Q.C.		√	√	√		√
Richard M. Thomson, O.C. [4]	√	√	Chair	√		
John M. Willson	√	√	√		Chair	
Victor J. Zaleschuk				Chair	√	√

Notes:

1 *All members are independent. All Audit Committee members are independent under additional regulatory requirements applicable to them.*

2 *Experience of the members of the Audit Committee that indicates an understanding of the accounting principles we use to prepare our financial statements is shown in their biographies on page 131.*

3 *A majority of the Reserves Review (Reserves) Committee are independent.*

4 *Audit committee financial expert under US regulatory requirements.*

5 *The board has determined that Mr. O'Neill's service on the audit committees of three other public companies and one not–for–profit organization does not impair his ability to serve as Chair of Nexen's Audit Committee. The board considered that Mr. O'Neill had a 30+ year career as a Chartered Accountant and, since retiring as Chair of PWC Consulting in 2002, his only business commitments are to the boards and committees on which he serves.*

Audit Committee Financial Expert Experience

Name	Experience
Jenkins	Kevin Jenkins, 51, is Managing Director of TriWest Capital Partners, an independent private equity firm. He was President, CEO and a director of The Westaim Corporation from 1996 to 2003, with businesses including technology investments, production of coin blanks, aerospace coatings and surface engineered products. From 1985 to 1996 he held senior executive positions with Canadian Airlines International Ltd. (Canadian). He was elected to serve on Canadian's board of directors in 1987, appointed President in 1991 and appointed President and CEO in 1994. Mr. Jenkins has a Bachelors Degree in Law from the University of Alberta and a Masters of Business Administration from Harvard Business School. He has worked in management positions with increasing level of responsibility including assistant treasurer, vice president finance, executive vice president and chief financial officer, and president and CEO. Kevin is Chair of Young Life of Canada and Vice Chair of World Vision Canada.
O'Neill	Tom O'Neill, 62, is the retired Chair of PwC Consulting. He was formerly CEO of PwC Consulting, COO of PricewaterhouseCoopers LLP, Global, CEO of PricewaterhouseCoopers LLP, Canada and Chair and CEO of Price Waterhouse Canada. He worked in Brussels in 1975 to broaden his international experience and from 1975 to 1985 was client service partner for numerous multi nationals, specializing in dual Canadian and US listed companies. Mr. O'Neill has a Bachelor of Commerce Degree from Queen's University. He received his Chartered Accountant designation in 1970 and was made a Fellow (FCA) of the Institute of Chartered Accountants of Ontario in 1988. He also has an Honourary Doctorate of Law from Queen's University. Tom is a director of BCE Inc., Loblaw Companies Limited and Adecco S.A. He is a member of the External Audit Committee of the International Monetary Fund. He is also Vice Chair of the Board of Governors of Queen's University and a director of St. Michael's Hospital.
Thomson	Dick Thomson, 74, is a retired banking executive. He was with the Toronto-Dominion Bank, one of Canada's largest banks, since 1957, as President from 1972 to 1978 and as Chair from 1978 until his retirement in 1998. Mr. Thomson holds a Masters of Business Administration from Harvard Business School and a Bachelor of Arts and Science in Engineering from the University of Toronto. He is an Officer of the Order of Canada. Dick is a director of The Thomson Corporation. He is also a member of the board of the Multiple Sclerosis Scientific Research Foundation.

Directors' and Officers' Liability Insurance

We maintain a directors' and officers' liability insurance policy. The policy provides coverage for costs incurred to defend and settle claims against directors and officers of Nexen to an annual limit of US$150 million with a US$12.5 million deductible for an indemnifiable occurrence and no deductible for a non-indemnifiable occurrence. The cost of coverage for 2007 was approximately US$1 million. Directors and officers do not pay any portion of the premiums and no indemnity claims were made or paid in 2007.

Directors' and Officers' Fiduciary Insurance

Nexen maintains a fiduciary liability insurance policy. It provides coverage for costs incurred to defend and settle claims against Nexen, our directors, officers and employees for breach of fiduciary duty in connection with company sponsored plans, such as pension and savings plans. The policy has an annual limit of US$25 million with a US$2.5 million deductible for an indemnifiable occurrence and no deductible for a non-indemnifiable occurrence. The cost of coverage for 2007 was approximately US$30,000. Directors and officers do not pay any portion of the premiums and no claims were made or paid in 2007.

Loans to Directors

As set out in the corporate governance policy, we do not make loans to our directors. There are no loans outstanding from Nexen to any of our directors.

DIRECTOR COMPENSATION

Nexen provides its directors with a comprehensive compensation package consisting of annual cash retainers, meeting fees and equity-based incentives in the form of deferred share units (DSUs). The total compensation package provides a competitive level of remuneration for the increasing responsibilities, time commitments and accountability of board members. All elements of director compensation are reviewed annually for competitiveness against a peer group of oil and gas companies by management, the Compensation Committee and the board. Our compensation philosophy targets and currently provides total compensation between the 50th and 75th percentile. This is intended to attract and retain qualified talent to serve on our board.

Directors may choose to receive select benefits coverage at Nexen's expense, including basic life insurance, extended health care, dental, business travel accident insurance, and the reimbursement of provincial health care premiums (in certain jurisdictions). Mr. Zaleschuk, a former CEO of Nexen is a retiree in the Nexen pension plan. The pension benefit provided to him is for previous service as an employee.

See page 132 for the changes to director compensation made January 1, 2008 and page 133 for more information on DSUs.

Director Summary Compensation Table

Name	Total Fees Earned[1]	DSU Awards[2]	All Other Compensation[3]	Total Compensation
Fischer[4]	–	–	–	–
Flanagan	107,933	141,950	97,178[5]	347,061
Hentschel	104,300	141,950	2,787	249,037
Jackson	124,700	141,950	3,242	269,892
Jenkins	126,500	141,950	4,007	272,457
McLellan	121,200	141,950	1,128	264,278
Newell	110,967	141,950	4,254	257,171
O'Neill	143,600	141,950	3,692	289,242
Saville	271,200	227,120	3,219	501,539
Thomson	131,000	141,950	5,665	278,615
Willson	127,400	141,950	3,920	273,270
Zaleschuk	106,600	141,950	2,823	251,373
Total	**1,475,400**	**1,646,620**	**131,915**	**3,253,935**

Notes:

1 *Includes all retainers and meetings fees, including those paid in DSUs.*

2 *The value of DSUs granted on December 3, 2007, based on the closing market price of Nexen common shares on the TSX on November 30, 2007 of $28.39.*

3 *The total value of perquisites provided to each director is less than both $50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2007 valued at the closing market price of Nexen common shares on the TSX on the payment dates, travel allowance paid by Nexen, and Canexus fees as set out in note 5.*

4 *As an executive of Nexen, Mr. Fischer is not paid any director compensation.*

5 *Mr. Flanagan is the Board Chair of Canexus and was paid fees of $57,500, received deferred trust units of Canexus valued at $29,340 and distributions on his trust units of $7,665 in 2007. The total is included in this column.*

Director Retainers and Fees

Annual board and committee retainers are paid quarterly and pro-rated for partial service. The same fees are paid for attending meetings in person or by conference call. A travel allowance of $1,500 was introduced on February 15, 2007. It is paid whenever a director travels outside of his or her home province or state, or travels more than a total of three hours, round trip, to attend a Nexen meeting or site visit. Nexen also reimburses directors for out-of-pocket travel expenses. New retainers were approved as of January 1, 2008.

	2007	2008
Board Chair Retainer	178,100[1]	250,000[2]
Board Member Retainer	28,100	35,000
Audit Committee Chair Retainer	19,700	19,700
Other Committee Chair Retainer	5,300	5,300
Committee Member Retainer	9,100	9,100
Board and Committee Meeting Fees (per meeting attended)	1,800	1,800

Notes:

1 *Total of the Board Chair Retainer of $150,000, plus the Board Member Retainer of $28,100.*

2 *As of January 1, 2008, the Board Chair is paid only this retainer and the travel allowance. He does not receive any other retainers or meetings fees.*

2007 Retainers and Fees

Name	Annual Board Retainer	Annual Committee Retainer	Annual Committee Chair Retainer	Board Meeting Fees	Committee Meeting Fees	Travel Allowance	Total Fees Earned	Total Fees Credited in DSUs[1]	Total Fees Earned in Cash
Fischer[2]	–	–	–	–	–	–	–	–	–
Flanagan	28,100	30,333	–	16,200	28,800	4,500	107,933	–	107,933
Hentschel	28,100	27,300	–	16,200	25,200	7,500	104,300	–	104,300
Jackson	28,100	36,400	5,300	16,200	34,200	4,500	124,700	120,200	4,500
Jenkins	28,100	36,400	5,300	16,200	36,000	4,500	126,500	–	126,500
McLellan	28,100	36,400	–	16,200	36,000	4,500	121,200	116,700	4,500
Newell	28,100	33,367	–	16,200	28,800	4,500	110,967	106,467	4,500
O'Neill	28,100	36,400	19,700[3]	16,200	34,200	9,000	143,600	–	143,600
Saville	178,100	36,400	–	16,200	36,000	4,500	271,200	–	271,200
Thomson	28,100	36,400	5,300	16,200	36,000	9,000	131,000	122,000	9,000
Willson	28,100	36,400	5,300	14,400	34,200	9,000	127,400	–	127,400
Zaleschuk	28,100	27,300	5,300	16,200	25,200	4,500	106,600	28,100	78,500
Total	**459,100**	**373,100**	**46,200**	**176,400**	**354,600**	**66,000**	**1,475,400**	**493,467**	**981,933**

Notes:

1 *Details of DSU holdings are set out in the table on page 133*

2 *As an executive officer of Nexen, Mr. Fischer is not paid any director compensation.*

3 *Mr. O'Neill is the Audit Committee chair.*

Share Ownership Guideline

Directors demonstrate their commitment to Nexen's success through share ownership. On February 14, 2008, the board approved guidelines that set out that directors are expected to own or control at least 16,800 shares or DSUs. This amount represents at least three times both the base annual board retainer of $35,000 and the value of the base annual DSU grant. They must be accumulated as follows:

- 5,600 by end of year 1
- 11,200 by end of year 2
- 16,800 by end of year 3

New directors will be required to take their base annual retainer in DSUs until the current threshold is met. If there is a change in share value or size of the annual grant of DSUs that causes a director to no longer meet the requirement, he or she will have nine months to meet the threshold again.

All directors surpass these guidelines.

Deferred Share Units

Nexen has two DSU plans. Under the first plan, eligible directors may elect annually to receive all or part of their fees in DSUs, rather than cash. Under the second plan, DSUs replaced stock options in 2003 as the long-term incentive used to align the interests of directors with shareowners.

DSUs provide directors with a stake in Nexen during their term of service. DSUs don't grant the right to vote as there are no shares underlying the plans. A DSU is a bookkeeping entry that tracks the value of one Nexen common share. When cash dividends are paid on Nexen common shares, eligible directors are credited with additional DSUs, equal to the value of the dividend paid. DSUs accumulate over a director's term of service and are only paid out when the director leaves the board. At that time, payments may be made in cash or in Nexen common shares purchased on the open market, at Nexen's option.

Name	DSUs Held as of December 31, 2007 [1]
Fischer	–
Flanagan	30,536
Hentschel	30,531
Jackson	37,989
Jenkins	43,611
McLellan	17,052
Newell	47,988
O'Neill	40,453
Saville	37,962
Thomson	62,322
Willson	43,025
Zaleschuk	32,298

Note:

1 Number of DSUs has been adjusted to account for Nexen's share splits that occurred in May 2005 and May 2007.

DSUs Granted in 2007

Position	Grant Date	DSUs (#)	Base Price [1] ($)	Value of DSUs [2] ($)
Board Chair	Dec 3, 2007	8,000	28.39	227,120
Other non-executive directors	Dec 3, 2007	5,000	28.39	141,950

Notes:

1 The closing market price of Nexen common shares on the TSX on November 30, 2007.

2 The number of DSUs times the base price

TOPs Exercised or Exchanged and Awards Vested During 2007

All exercises or exchanges of tandem options (TOPs) in 2007 occurred within nine months of their expiry. There are no vesting provisions and no value realized on vesting under the DSU plan.

	TOPs Awards		DSU Awards	
Name	Exercised or Exchanged (#)	Value Realized [1] ($)	Shares Acquired on Vesting (#)	Value Realized ($)
Flanagan	7,260	157,742	–	–
Hentschel	22,000	445,885	–	–
Jackson	22,000	517,165	–	–
Jenkins	22,000	484,385	–	–
O'Neill	22,000	503,305	–	–
Saville	7,260	157,669	–	–
Thomson	33,200	776,133	–	–
Willson	7,332	197,066	–	–
Total	**143,052**	**3,239,350**	**–**	**–**

Note:

1 Market price at the time of the exercise or exchange, minus the exercise price, as defined in the Tandem Option (TOPs) plan.

COMPENSATION COMMITTEE REPORT

The Compensation Committee assists the board in overseeing key compensation and human resources policies, CEO and executive compensation, and executive management succession and development. The Committee reports to the board, as set out in its mandate, and the board or independent directors give final approval to compensation matters.

All members of the Committee are independent and knowledgeable about our compensation programs and policies. Five members of the Committee are skilled or expert in compensation, the area of expertise most relevant to carrying out the Committee's mandate.

Changes to Committee Membership in 2007

There were no changes to the Committee membership in 2007.

Key Activities in 2007

- Recommended compensation programs for base salary, annual cash and long-term incentives (Tandem Option (TOPs) Plan and Stock Appreciation Rights (STARs) Plan);
- Recommended salaries, bonuses and grants of TOPs to the executives;
- Assessed CEO performance on short-term and long-term corporate goals and objectives and recommended CEO compensation, which was approved by the independent directors of the board;
- Reviewed the CEO's annual objectives and our executive management succession and development plans;
- Evaluated and recommended organizational changes and officer appointments;
- Recommended special recognition awards for key business initiatives;
- Recommended director compensation, including DSU grants; and
- Reviewed existing change of control agreements for executives in light of current compensation.

Outside Consultant

The Committee engaged Mercer Human Resources Consulting (Mercer) to provide a confidential report and technical analysis of market data on the CEO's compensation, in light of our operations and compensation programs. Mercer also provided a compensation report on a select group of our executives. The reports included competitive information from a list of peer companies recommended by Mercer. The decisions of the Committee are their responsibility and may reflect factors other than the information and recommendations provided by Mercer and management.

Mercer did not provide any compensation consulting services to management in 2007. We participated in compensation surveys in Canada and international locations and purchased select published results. Management must obtain Committee approval before retaining Mercer for any compensation consulting work.

Fees Billed by Outside Consultant (Mercer)

Type of Fee	Billed in 2006	Billed in 2007	Percentage of Total Fees billed in 2007
Committee work—Assessment of CEO and executive compensation	37,780	49,610	100%
Management work—Administrative services	3,470	–	–
Total Annual Fees	**41,250**	**49,610**	**100%**

External Recognition and Verification

Nexen was recognized for its human resource practices during 2007, including being named one of:

- Canada's 50 Best Employers in Canada by Hewitt Associates Inc.;
- Alberta's Top Employers by Mediacorp Canada Inc.; and
- Canada's 30 Best Pension and Benefits Plans by Benefits Canada magazine.

Committee Approval

The Committee has reviewed and discussed with management the compensation disclosure in this document, including the information in the Board of Directors section on pages 131 through 132, in the Compensation Overview section on pages 135 through 140 and in the Executive Compensation section on pages 142 through 150, and has recommended to the board that it be included in the Management Proxy Circular for the 2008 Annual General and Special Meeting of Shareholders and, as appropriate, Form 10-K.

Submitted on behalf of the Compensation Committee:

Kevin Jenkins, Chair
Barry Jackson
Anne McLellan
Tom O'Neill
Francis Saville
Dick Thomson
John Willson

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation Committee are set out on page 130. Mr. Saville had a relationship requiring disclosure, the details of which are set out under "Certain Relationships and Related Transactions, and Director Independence" on page 155. There are no Compensation Committee interlocks during 2007.

COMPENSATION OVERVIEW

Compensation Disclosure

Our compensation disclosure complies with the requirements of the Canadian Securities Administrators. As a foreign private issuer in the US, we are not required to disclose compensation according to the SEC rules issued in 2006. We have, however, complied with the spirit of those rules where possible, without compromising required Canadian disclosure.

Compensation Philosophy

Our policies and practices for executive compensation are linked to strategic business objectives, including increasing shareowner returns. Our philosophy is to compensate executives:

- based on performance;
- at a level competitive with our peers; and
- in a manner designed to attract and retain talented leadership focused on managing Nexen's operations, finances and assets.

All of our compensation programs are designed to meet pay-for-performance and competitiveness objectives. Actual rewards are directly linked to the results of Nexen and our divisions. The objective and subjective performance measures are aligned with shareowner interests, including financial and non-financial goals. Measures set each year represent improvements to our operations.

Our programs are responsive to market changes. We aim for simplicity in our compensation programs to help employees understand the value of the various components. Executive programs are generally consistent with employee programs in the same location. Where certain programs, such as perquisites, are only provided to executives or senior management, they reflect competitive practice and particular business needs and objectives.

Benchmark Review

We use third-party compensation surveys to compare our pay levels and practices, including base pay, annual cash incentives and long-term incentives, to our peers. We look mainly at Canadian-based oil and gas and integrated pipeline companies with whom we compete for talent. Given similar positions across the industry, the surveys effectively represent competitive pay levels. It should be noted, however, we do not know the extent to which our peers particpate in the surveys and benchmark each position. The peer group is modified in some cases to reflect (i) geographical location, (ii) a particular business line, (iii) a more comparable position, or (iv) industry mergers and acquisitions.

The composition of our peer group is reviewed annually by third-party consultants and the Compensation Committee for continued relevance. In 2007, our executive peer groups comprised up to 16 companies, including the following publicly-traded companies:

Canadian Natural Resources Limited
Enbridge Inc.
EnCana Corporation
Husky Energy Inc.
Petro-Canada
Suncor Energy Inc.
Talisman Energy Inc.
TransCanada Corporation

The Compensation Committee reviews all programs to ensure we continue to attract and retain the high-performing employees needed to achieve our business objectives, while demonstrating long-term fiscal responsibility to shareowners.

Compensation Objectives

Our compensation programs include three components: base salary, annual cash incentive and long-term incentive. At least once a year we assess the competitiveness of these individual components and the overall compensation. Our goal is to provide total compensation for top performing employees between the 50th and 75th percentile as compared to our peers.

Key Elements of Compensation

Element	Component	Form	Performance Period
Base salary	Fixed	Cash	1 year
Annual cash incentive	Variable	Cash	1 year
Long-term incentive	Variable	TOPs and STARs	Greater than 1 year

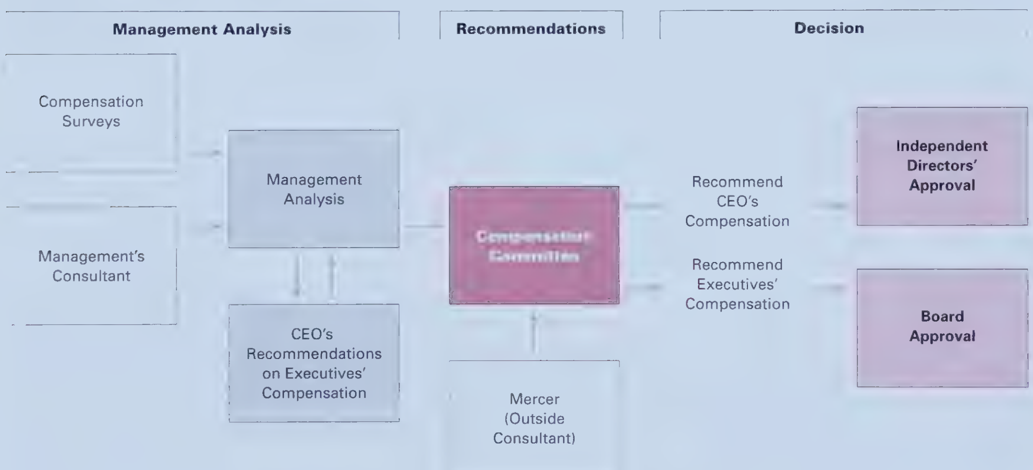
Target Weightings

Since our compensation programs are designed to meet both performance and competitiveness objectives, actual pay will vary from year to year against the target weightings. In general, the targets are designed to provide most executive compensation in the form of at-risk pay to ensure alignment with shareowners. Base salary provides a competitive foundation considering both internal comparability and external market data. Annual cash incentives reward the delivery of results against objective and subjective measures within a one-year period. Long-term incentives reward Nexen's sustained performance as seen in share price appreciation. The actual mix between the compensation elements varies, depending on the executive's ability to influence short and long-term business results, their level, and competitive local market practices.

		At-Risk Compensation [1]	
Position	**Base Salary**	**Annual Cash Incentive**	**Long-Term Incentive**
CEO	20%	15%	65%
CFO/Executive VPs	25%	20%	55%
Senior VPs	30%	20%	50%

Note:
1 Represents the percentage of total compensation, excluding benefits, pension and perquisites.

Compensation Approval Process



In determining our executives' base salary, annual cash and long-term incentives, the Compensation Committee considers a comprehensive analysis, including a tally sheet prepared by management with help from an executive compensation consultant. The analysis includes market data for similar positions within the peer group and CEO recommendations for his direct reports, including all of the other named executive officers (executives) and information on prior year annual cash and long-term incentives. Management also provides a sensitivity analysis that considers the pension cost implications for each 1% of incremental pensionable earnings.

The Committee reviews the various compensation elements both individually and in total to ensure they align with the program objectives. In addition, the Committee retains the services of its own executive compensation consultant, Mercer, to provide external market data and commentary on the relative positioning of executives, particularly the CEO. The Committee then makes recommendations on all executive payments and grants to the board or independent directors for approval. Typically, this process begins in the fall and concludes with total compensation being approved the following February.

Base Salaries

A framework of job levels based on internal comparability and external market data is used to determine base salaries, considering the individual's current and sustained performance, skills and potential.

Annual Cash Incentives

The program provides competitive bonus compensation that reflects Nexen's overall performance and that of the individual.

2007 Annual Incentive Measures

The board, at the recommendation of the Compensation Committee, approves the factor that determines the cash pool available for annual cash incentives after reviewing Nexen's objective and subjective performance measures. The factor may range from 0 to 200%. The factors used were 200% in 2005, 120% in 2006 and 88% in 2007.

2007 Objective Performance Measures (50%)

Measure	Target	Results	Results versus Target
Cash flow (25%)	$3,290 million	$3,458 million	105%
Net income (25%)	$981 million	$1,086 million	111%

2007 Subjective Performance Measures (50%)

The Compensation Committee subjectively considers 19 business measures commonly used in our industry. They include, among other things, stock performance, annual stock performance against peers, production volumes, safety and environmental incidents, and reserve-related metrics. The Committee also assesses costs, including finding and development, operating and administrative. The business measures are assessed against objectives in light of our external environment and current business circumstances, including key projects and initiatives critical to Nexen's success. Both absolute performance and performance relative to peers are reviewed. The Committee also considers management's assessment of Nexen's performance and progress against the strategic plan. The Committee exercises its discretion in assessing Nexen's overall performance and may increase or decrease the total cash available for these awards. For 2007, the Committee considered that, while our financial results were strong, we were not as successful in achieving certain other business targets.

The cash pool available for annual incentives is then allocated to employees and executives based on individual target levels and performance. The targets for individual awards increase as job responsibilities grow so that the ratio of at-risk versus fixed compensation is greater for higher levels of responsibility. Individual performance is assessed by the direct supervisor and reflects performance against pre-determined objectives. The actual incentive award received by the executive may be more or less than the target level. Typically, executive awards range from 0 to 200% of the target for that position.

2007 Annual Incentive Targets [1]

Position	Minimum	Target	Maximum
CEO [2]	0%	80%	160%
CFO/Executive VPs	0%	60%	120%
Senior VPs	0%	45%	90%

Notes.

1 Reflects percentage of base salary on December 31, 2007

2 To ensure competitive compensation, the independent directors of the board increased the target from 75% to 80% and the maximum from 150% to 160% effective January 1, 2007

Reimbursement

If, as a result of misconduct, Nexen's performance results were restated in a way that decreased the incentive awards, the CEO and CFO would reimburse Nexen proportionately as required by law.

Share Ownership Guidelines

All executive officers demonstrate their commitment to Nexen by holding more shares than required under our board approved guidelines. Shares must be accumulated within five years from date the executive was appointed. Share ownership includes the net value of exercisable options or TOPs, flow-through shares, shares purchased and held within the Nexen employee savings plan and any other personal holdings. The guidelines are reviewed periodically by the Compensation Committee and the board. See page 144 for the current share ownership of each executive.

Position	Required Share Ownership
CEO	Three times annual salary
CFO	Two times annual salary
Other executive officers	One times annual salary

Long-term Incentives

The TOPs and STARs plans provide employees with a long-term incentive to continue high performance, demonstrate commitment to Nexen and, most importantly, align their interests with those of our shareowners. As Nexen's share price rises, grants increase in value. Nexen's long-term incentive program (the TOPs and STARs plans) are granted to officers and employees whose actions can most directly impact our business results.

In determining the number of TOPs and STARs to grant each year, Nexen considers the program's dilutive impact on shareowners and market information on options and other forms of long-term incentives. Market information also determines the extent to which employees at different levels participate in the program. Management and the Compensation Committee have considered alternative long-term incentive programs used by our peers, including full-value plans such as DSUs, restricted share units and performance-based stock options. At this time, TOPs and STARs continue to best meet Nexen's objectives, considering competitive position, retention value, tax effectiveness for both our employees and Nexen, shareowner interests, and dilution levels.

TOPs Plan

Our TOPs plan has been in place since 2004. It allows employees to either:

- exchange their vested TOPs for a cash payment equal to the difference between the grant price and the closing market price of our common shares on the date the TOPs were exchanged; or
- exercise their TOPs for shares.

When employees exchange their TOPs for cash: (i) no shares are issued, which prevents further shareowner dilution over time; and (ii) Nexen receives a Canadian income tax deduction.

2007 TOPs Plan Exercises and Exchanges

Total exercised or exchanged	6,670,714
Exercised for shares (percent)	2,256,954 (34%)
Exchanged for cash (percent)	4,413,760 (66%)

TOPs do not provide employees with the right to vote the underlying shares. The TOPs plan is Nexen's only equity-based compensation arrangement for the purposes of disclosure requirements.

The board, on the recommendation of the Compensation Committee, may grant TOPs to Nexen officers and employees. TOPs granted before February 2001 have a term of ten years; 20% of the grant vested after six months and 20% vested each year for four years on the grant's anniversary. TOPs granted after February 2001 have a term of five years and vest one-third each year for three years.

Generally, if a change of control event occurs (as defined in the TOPs plan), all issued but unvested options will vest. The board approved minor amendments to the TOPs plan in 2007.

STARs Plan

The STARs plan, introduced in 2001, provides a cash payment to participants equal to the appreciation in Nexen's share price between the date the STARs are granted and the date they are exercised. STARs are typically granted to employees below mid-level department manager. They have a five-year term and vest one-third each year for three years.

Grant Date and Exercise Price

TOPs and STARs are granted during the annual grant process and at the time of hiring key positions. Since 1998, the annual grants have been approved at the December board meeting. According to our plans, the CEO can approve grants to key new hires and typically they occur shortly after the hire date. Under the plans, the exercise price is the closing market price of Nexen's common shares on the relevant stock exchange (TSX for Canadian-based employees or NYSE for US-based employees) on the day before the grant is approved. Accordingly, backdating is not allowed. Nexen's grants are not intentionally timed to occur immediately prior to the release of material information (spring-loaded). The exercise price of existing TOPs or STARs may not be reduced except for automatic adjustments under the plans (for example, on share splits) or according to TSX rules.

Grants in the Last Three Years

Our 2007 long-term incentives recognized high performance, future potential within Nexen and retention risk.

Year	Granted to Executive Officers	Granted to Employees	Percentage of Employees Receiving Grants	Total Number Granted
TOPs				
2007	1,735,000	2,272,100	7%	4,007,100
2006 [1]	1,480,000	3,321,000	7%	4,801,000
2005 [1]	1,184,000	5,599,000	20%	6,783,000
STARs				
2007	–	4,194,600	54%	4,194,600
2006 [1]	–	4,508,600	51%	4,508,600
2005 [1]	–	2,886,100	39%	2,886,100

Note:

1 Numbers of TOPs and STARs granted have been adjusted to account for Nexen's two-for-one share split in May 2005 and May 2007.

Benefit and Pension Plans

Our benefit and pension plans support the health and well-being of our employees, and encourage retirement savings. The plans are reviewed periodically to ensure they remain competitive and continue to meet our objectives. Market survey data is reviewed to ensure the plans provide benefits between the 50th and 75th percentile of plans within our peer group of companies. Executives participate in the same plans provided to all employees at the same location.

Disclosure in this document is specific to the Canadian and US plans in which the executives participate. Nexen provides a variety of other benefit and pension plans outside of Canada and the US that reflect local market practices.

Health and Welfare Benefits

Our benefit plans are designed to protect employees' health and that of their dependents, and cover them in the event of disability or death. Under the flexible benefits plans, employees choose the level of coverage that best fits their needs. Those who select enhanced coverage levels are required to contribute to the cost of that coverage.

Employee Savings Plan

In the employee savings plan, all eligible Canadian employees may contribute, through payroll deduction, any percentage of their base salary to purchase Nexen common shares, mutual fund units or a combination of both. Nexen matches employee contributions up to 6% of base salary, depending on the investment option and how long the employee has participated in the plan. Nexen contributions are invested in our common shares purchased on the open market and vest immediately. All contributions may be allocated to registered or non-registered accounts. Employees may vote the Nexen common shares they hold in their employee savings plan.

The employee savings plan in the US is intended to qualify under Section 401(a) and 501(a) of the Internal Revenue Code. Nexen's matching contribution, of up to 6% of eligible compensation, is provided in cash, which vests immediately.

Defined Benefit Pension Plan (Canada)

Canadian employees of Nexen elect, upon hire, to participate in either the defined contribution pension plan or the defined benefit pension plan, both of which are registered. All executives participated in the defined benefit pension plan in 2007. It is funded by a pension trust and features:

- participant contributions at 3% of their regular gross earnings (up to an annual plan maximum);
- retirement benefits at 1.8% (1.7% for years prior to 2005) of their average earnings for the 36 highest-paid consecutive months during the ten years before retirement, multiplied by the years of credited service;
- integration with Canada Pension Plan (CPP) to provide a maximum offset of one-half of the current CPP benefit;
- benefits on retirement that are generally paid monthly for the life of the retiree, subject to payment elections; and
- ability for participants to periodically switch between the defined benefit pension plan and defined contribution pension plan at different stages in their career.

Pension benefits earned prior to January 1, 1993, may be indexed at the discretion of management's pension committee, considering increases in the consumer price index. Pension benefits earned after December 31, 1992, are indexed annually between 0 and 5% based on the greater of:

- 75% of the increase in the consumer price index, less 1%; and
- 25% of the increase in the consumer price index.

Plan participants may increase their defined benefit accrual formula on a go-forward basis, from 1.8% to 2%. Employees who choose this option must contribute an additional 2% of pensionable earnings up to an allowable maximum under the Canadian Income Tax Act. The maximum employee contribution allowed under the defined benefit pension plan in 2007 was $10,700.

Executive Benefit Plan (Canada)

The executive benefit plan is available to all Canadian employees. It provides supplemental retirement benefits for participants who have earned a retirement benefit in excess of the statutory limits, which varies by employees' pension elections. This allows employees to accrue a pension that is aligned with their final earnings level and is competitive within our market. Under this plan, benefits accrue and are paid monthly in a similar manner to the underlying defined benefit pension plan set out above on page 139. For executives, annual cash incentive payments during the last three years they participated in this plan are included for benefit accrual purposes. For annual cash incentives, the pension benefit is accrued on the lesser of target bonus or actual bonus paid, averaged over the final three years of participation.

Pension Benefit Security

The pension expense for this supplemental plan is accounted for annually. Benefits are paid from Nexen's cash flows and reduce the related pension liability. As liabilities under this plan are not funded outside of Nexen, a level of protection is provided to participants through a letter of credit. The letter of credit is intended to make participants secured creditors for the total value of Nexen's unfunded pension obligation. The cost of servicing the letter of credit in 2007 for all plan participants was $509,135.

Pension Benefit Obligation

At December 31, 2007, as indicated in the notes to our financial statements, the:

- supplemental pension plan's accumulated benefit obligation (the projected benefit obligation, excluding future salary increases) for the executive benefit plan was $48 million; and
- projected benefit obligation was $62 million.

The projected benefit obligation is an estimate based on contractual entitlements that may change over time. The method used to determine this estimate will not be identical to those used by others and, as a result, the estimate may not be directly comparable across companies. The key assumptions used for the projected benefit obligation were:

- a discount rate of 5.25% per year;
- a long-term compensation rate increase of 4% per year; and
- an expected average remaining service life of ten years.

As of January 1, 2005, the executive benefit plan was amended to provide a supplemental pension allocation for defined contribution pension plan participants who are impacted by annual statutory contribution limits. In 2007, the supplemental allocation for eligible participants was $35,341 and is estimated to be $37,000 in 2008.

Defined Contribution Pension Plan (US)

All US employees participate in this qualified retirement plan. Nexen contributes 6% of eligible compensation up to the social security wage base, and, 11.5% of eligible compensation that exceeds the social security taxable wage base. For 2007, Nexen's maximum contribution per participant was US$20,513. Employees are not permitted to contribute to the plan. Investment decisions are made by the employee from a variety of mutual funds. The contributions vest after two years of service. This plan is intended to be an Employee Retirement Income Security Act (ERISA) 404(c) plan. Only one executive participated in the defined contribution pension plan for US employees in 2007.

Non-Qualified Restoration Plan (US)

This supplemental plan is available to all US employees. It is an unfunded arrangement that provides deferred compensation benefits to participants who have earned a retirement benefit in excess of the statutory limits. The returns in this plan reflect the returns on the investments selected by the employee. The plan complies with Section 409A of the Internal Revenue Code.

Loans to Officers

As set out in the corporate governance policy, Nexen does not make loans to its officers. There are no loans outstanding from Nexen to any of its officers.

EXECUTIVE OFFICERS

The board determines the term of office for each executive officer. Below are Nexen's officers, including prior offices and non-executive positions for officers who have held their current executive positions with Nexen for less than five years. Start dates are indicated for officer positions with Nexen.

Officer (Age)	Current and Past Position(s) with Nexen	Effective Date of Current Position	Executive Officer Since
Charles W. Fischer (57)	President and CEO and a director	June 1, 2001	1994
Marvin F. Romanow (52)	Executive VP and CFO	June 1, 2001	1997
Laurence Murphy (56)	Executive VP, International Oil and Gas Formerly: Senior VP, International Oil and Gas since January 1, 1999	November 1, 2007	1998
Roger D. Thomas (55)	Executive VP, North America Formerly: Senior VP, Canadian Oil and Gas since February 19,1999	November 1, 2007	1998
Gary H. Nieuwenburg (49)	Senior VP, Synthetic Crude Formerly: VP, Synthetic Crude since July 11, 2002	November 1, 2007	2001
Kevin J. Reinhart (49)	Senior VP, Corporate Planning and Business Development Formerly: VP, Corporate Planning and Business Development since July 11, 2002	November 1, 2007	1994
Brian C. Reinsborough (46)	Senior VP, United States Oil and Gas Formerly: Division VP, Exploration, Operations and Production since May 12, 2006; Division VP, Exploration since July 8, 2002	November 1, 2007	2007
Timothy J. Thomas (50)	Senior VP, Canadian Oil and Gas Formerly: Division VP, Exploration and Production, Canadian Oil and Gas since April 1, 2004; Division VP, Yemen Operations and International Business Development since January 1, 2003	November 1, 2007	2007
Randy J. Jahrig (52)	VP, Human Resources and Corporate Services Formerly: Division VP, Human Resources Canada and International since April 1, 2002	April 26, 2007	2007
Kim D. McKenzie (59)	VP and Chief Information Officer Formerly: Division VP, Information Technology since January 1, 1992	November 1, 2007	2007
Eric B. Miller (45)	VP, General Counsel and Secretary Formerly: Division VP and Chief Legal Counsel since July 1, 2006; Division VP, Legal Canadian Oil and Gas since March 1, 2002	July 11, 2007	2007
Una M. Power (43)	Treasurer	July 11, 2002	1998
Brendon T. Muller (39)	Controller Formerly: Manager, Corporate External Reporting since November 1, 2003; Team Lead, Corporate Accounting since April 1, 2002	April 9, 2007	2007

SHARE SPLITS

All grant prices and numbers granted have been adjusted to account for the May 2005 and May 2007 share splits.

SUMMARY COMPENSATION TABLE

The compensation for the CEO, CFO and the next three highest paid officers (named executive officers or executives), plus Mr. Douglas Otten who retired November 1, 2007, is provided. To determine the next three highest paid officers we total their salary, special bonus and non-equity cash incentive compensation as show below.

		Annual			Long-Term		Other		
Name and Principal Position	Year	Salary ($)	Special Bonus[1] ($)	Non-Equity Cash Incentive Compensation[2] ($)	TOPs Awards (#)	TOPs Awards[3] ($)	Changes in Pension Obligations[4] ($)	All Other Compensation[5,6] ($)	Total Compensation[6] ($)
Charles W. Fischer,	2007	1,275,000	–	916,000	600,000	5,110,200	949,300	119,640	8,370,140
President	2006	1,150,000	500,000	1,300,000	550,000	5,010,654	1,673,800	111,621	9,746,075
and CEO	2005	975,000	300,000	1,500,000	400,000	3,110,490	879,300	101,364	6,866,154
Marvin F. Romanow,[7]	2007	566,250	–	330,000	180,000	1,533,060	323,300	117,129	2,869,739
Executive VP	2006	528,000	–	402,000	160,000	1,457,645	534,800	118,073	3,040,518
and CFO	2005	486,000	175,000	590,000	124,000	964,252	176,300	89,557	2,481,109
Laurence Murphy,									
Executive VP,	2007	495,833	–	303,000	165,000	1,405,305	583,300	57,214	2,844,652
International	2006	455,000	300,000	342,000	130,000	1,184,336	580,800	53,711	2,915,847
Oil and Gas	2005	405,000	–	410,000	100,000	777,623	141,300	44,439	1,778,362
Roger D. Thomas,	2007	487,500	–	275,000	165,000	1,405,305	792,300	56,690	3,016,795
Executive VP,	2006	445,000	–	336,000	130,000	1,184,336	735,800	53,086	2,754,222
North America	2005	394,250	200,000	400,000	100,000	777,623	167,300	50,773	1,989,946
Gary H. Nieuwenburg,	2007	360,667	–	191,000	100,000	851,700	267,300	48,775	1,719,442
Senior VP,	2006	328,850	–	210,000	100,000	911,028	284,800	51,944	1,786,622
Synthetic Crude	2005	303,050	7,500	275,000	80,000	622,098	61,300	50,459	1,319,407
Douglas B. Otten,[8]	2007	387,763	–	201,245	–	–	–	93,518	682,526
Senior VP,	2006	439,716	–	326,938	110,000	990,017	–	107,228	1,863,899
US Oil and Gas	2005	423,489	–	430,154	100,000	815,163	–	102,853	1,771,659

Notes:

1 *Special discretionary award(s) are earned in the year shown and include cash awards approved by the board for successful delivery of key business objectives.*

2 *Reflects the value of awards earned in each year under Nexen's annual cash incentive program. The awards are paid to the executives in the following calendar year based on their salary on December 31 of the previous year.*

3 *Reflects the estimated fair value under the Black-Scholes pricing model of TOPs granted in the year.*

4 *Represents the employer service cost, plus changes in compensation in excess of actuarial assumptions, less required member contributions to the plan.*

5 *The total value of the perquisites portion of All Other Compensation provided to each executive is less than $50,000 and less than 10% of their total annual salary plus bonus. See the table on page 148 for details of these amounts.*

6 *Certain prior year numbers have been restated to include the total value of perquisites as described in note 5.*

7 *Mr. Romanow is a director of Canexus and was paid fees of $32,500, received deferred trust units of Canexus valued at $19,560 and distributions on his trust units of $4,259 in 2007. In 2006, he was paid fees of $34,000, received deferred trust units of Canexus valued at $24,000 and distributions on his trust units of $2,571. In 2005, he was paid fees of $13,875, received deferred trust units of Canexus valued at $20,000 and distributions on his trust units of $659. These amounts are included in the All Other Compensation table on page 148.*

8 *2007 TOPs grants occurred after Mr. Otten retired. Nexen contributed to a qualified defined contribution pension plan and a restoration plan with Nexen Petroleum U.S.A. Inc. for Mr. Otten, which are reported in All Other Compensation on page 148.*

Changes in Compensation Arrangements in 2007

The compensation paid to executives in 2007 is consistent with our philosophy and objectives of targeting total compensation between 50th and 75th percentile as detailed on pages 135 through 137. Variable compensation links to Nexen's business results and the executive's performance, consistent with our pay-for-performance philosophy. The decrease in the executives' annual cash incentives in 2007 reflects the board's assessment of our relative level of success on certain of our business objectives.

We did not introduce any new compensation or benefit programs in 2007 for Nexen's executives.

Changes in Pension Obligations

The summary compensation table shows the year-over-year change in pension obligations. The value reflects the employer service cost, plus any changes in obligations resulting from compensation increases over actuarial assumptions. Actual compensation changes may vary from the assumed rate of compensation increase and will vary among each executive from year to year. These values differ from pension benefit reported on page 147, which discloses estimated values of annual pension benefits earned to date, as well as at age 60 (the earliest unreduced retirement age). They also differ from the termination values reported under the change of control agreements on page 150, which disclose additional lump sum pension benefits provided if a change of control occurs.

CEO COMPENSATION AND 2007 GOALS

Mr. Fischer's responsibility is to provide leadership in setting and achieving goals that create value for our shareowners in the short term and long term. His 2007 annual cash incentive award was based on the corporate results described on page 137, which determined the total cash available for the awards. Cash incentive awards are determined from the available pool and distributed to individuals based on specific annual goals. Based on the board's assessment of Mr. Fischer's achievement of objectives in 2007 and their positive assessment of his contribution to continued shareowner value growth and strategic plan execution, he was awarded an annual cash incentive of $916,000 which was his target bonus times 88%. Specifically, Mr. Fischer's goals in 2007 were to:

- develop and implement a corporate strategy, balancing short-term growth while positioning Nexen for sustainable growth;
- achieve capital, operating, and general and administrative cost performance targets set out in the annual operating plan (AOP);
- achieve targets for operating cash flow, earnings, production levels and reserve replacement set out in the AOP;
- maintain financial flexibility and liquidity to support our business strategies;
- achieve top-quartile performance in health, safety and environmental performance and social responsibility;
- provide for corporate management succession and development;
- ensure Nexen adheres to the highest standards of integrity; and
- demonstrate his personal commitment to community and industry leadership.

CEO THREE-YEAR LOOK-BACK

	Total	2007	2006	2005
Cash				
Base Salary	3,400,000	1,275,000	1,150,000	975,000
Annual Cash Incentive [1]	4,516,000	916,000	1,800,000	1,800,000
Equity				
Value of TOPs [2]	13,231,344	5,110,200	5,010,654	3,110,490
Total Direct Compensation	21,147,344	7,301,200	7,960,654	5,885,490
All Other Compensation [3]	332,625	119,640	111,621	101,364
Annual Change in Pension Obligation [4]	3,502,400	949,300	1,673,800	879,300
Total Cost	**24,982,369**	**8,370,140**	**9,746,075**	**6,866,154**
Annual Average	8,327,456			
Total Market Capitalization Growth ($ millions)	10,640	90	2,370	8,180
Total Cost as a % of Market Capitalization Growth	0.23%			

Notes:

1 *Includes special bonuses of $500,000 in 2006 for the success of Buzzard and $300,000 in 2005 for successful divestitures*

2 *Reflects the estimated fair value of TOPs using the Black-Scholes pricing model valued on the grant date*

3 *See page 148 for details of All Other Compensation.*

4 *Represents the employer service cost, plus changes in compensation in excess of actuarial assumptions, less required member contributions to the plan*

In 2007, the Compensation Committee reviewed the information above and analyzed Mr. Fischer's total pay and shareowner value created from the date he became CEO. In the analysis, dollar values were assigned and tallied for each compensation component including salary, annual cash incentives, TOPs awards, benefits, pension (including annual increases to liabilities) and potential payments on change of control. The Committee reviewed his total compensation relative to Nexen's growth in shareowner value (market capitalization) and the growth of industry peers.

EQUITY OWNERSHIP AND CHANGES IN 2007

According to our share ownership guidelines, Mr. Fischer is required to hold three times his annual salary, Mr. Romanow, two times his annual salary and the other executives, one times their annual salary.

	Dec 31, 2006		Dec 31, 2007		Net Change		Equity at Risk	
Name	Shares	TOPs[1]	Shares	TOPs[1]	Shares	TOPs[2]	Value[3] ($)	Multiple of Salary[4]
Fischer	166,516	2,458,000	183,416	2,215,000	16,900	(243,000)	46,460,074	36
Romanow	51,874	814,920	80,938	785,480	29,064	(29,440)	16,729,050	30
Murphy	111,656	236,240	125,226	164,000	13,570	(72,240)	5,387,856	11
Thomas	8,580[5]	269,200	16,227	399,200	7,647	130,000	6,683,592	14
Nieuwenburg	59,040	238,800	65,795	265,600	6,755	26,800	5,944,054	16
Otten	70,072	460,288	34,458	254,952	(35,614)	(205,336)	5,483,913	14
Total	**467,738**	**4,477,448**	**506,060**	**4,084,232**	**38,322**	**(393,216)**	**86,688,539**	

Notes:

1 Represents total TOPs granted, vested and unexercised.

2 Reflects the number of TOPs that vested, minus the number exercised or exchanged during 2007.

3 Equity at risk is the market value of common shares and vested TOPs using the closing price of Nexen shares on the TSX on December 31, 2007 of $32.10.

4 Reflects the equity at risk, divided by the executive's 2007 salary amount shown on page 142

5 Amount includes eight common shares not previously reported.

TOPS TABLES

To value TOPs grants, Nexen uses the Black-Scholes pricing model, which is a generally accepted method for measuring this type of long-term incentive. The actual value realized on exercises may be higher or lower depending on the Nexen share price at the time of exercise.

TOPs Granted in 2007

							Potential Realizable Value at Assumed Annual Rates of Share Price Appreciation for TOPs Term	
Name	Grant Date	TOPs Granted (#)	% of Total TOPs Granted to Employees	Exercise Price[1] ($)	Expiry Date	TOPs Value[2] ($)	5% ($)	10% ($)
Fischer	Dec 3, 2007	600,000	15.0	28.39	Dec 2, 2012	5,110,200	4,706,180	10,399,427
Romanow	Dec 3, 2007	180,000	4.5	28.39	Dec 2, 2012	1,533,060	1,411,854	3,119,828
Murphy	Dec 3, 2007	165,000	4.1	28.39	Dec 2, 2012	1,405,305	1,294,200	2,859,843
Thomas	Dec 3, 2007	165,000	4.1	28.39	Dec 2, 2012	1,405,305	1,294,200	2,859,843
Nieuwenburg	Dec 3, 2007	100,000	2.5	28.39	Dec 2, 2012	851,700	784,363	1,733,238

Notes:

1 Reflects the closing market price of Nexen common shares on the TSX on November 30, 2007.

2 Reflects the estimated fair value of the TOPs as at December 3, 2007 using the Black-Scholes pricing model.

TOPs Exercised or Exchanged and Awards Vested in 2007

	TOPs Awards		Stock Awards[1]	
Name	Exercised or Exchanged (#)	Value Realized[2] ($)	Shares Acquired on Vesting (#)	Value Realized ($)
Fischer	760,000	18,182,000	–	–
Romanow	200,000	4,381,500	–	–
Murphy	202,240	4,802,413	–	–
Thomas	–	–	–	–
Niewenburg	73,200	1,860,128	–	–
Otten	300,608	7,566,047	–	–
Total	**1,536,048**	**36,792,088**	**–**	**–**

Notes:

1 Nexen does not provide stock awards to executives

2 Reflects the market price at the time of the exercise or exchange, minus the exercise price, as defined in the TOPs plan.

TOPs Holdings and Value of In-the-Money TOPs

					Vested and Unvested TOPs at Dec 31, 2007 [1,2]		Vested TOPs at Dec 31, 2007 [2]	
Name	Date Granted	Expiry Date	Grant Price ($)	Granted (#)	Number (#)	Value [3] ($)	Number (#)	Value [3] ($)
Fischer	Dec 15, 1998	Dec 14, 2008	4.4625	200,000	200,000	5,527,500	200,000	5,527,500
	Dec 14, 1999	Dec 13, 2009	6.8125	280,000	280,000	7,080,500	280,000	7,080,500
	Dec 12, 2000	Dec 11, 2010	9.0250	280,000	280,000	6,461,000	280,000	6,461,000
	Dec 9, 2003	Dec 8, 2008	10.8750	400,000	400,000	8,490,000	400,000	8,490,000
	Dec 7, 2004	Dec 6, 2009	12.7175	600,000	600,000	11,629,500	600,000	11,629,500
	Dec 6, 2005	Dec 5, 2010	27.2850	400,000	400,000	1,926,000	268,000	1,290,420
	Dec 4, 2006	Dec 3, 2011	31.6000	550,000	550,000	275,000	187,000	93,500
	Dec 3, 2007	Dec 2, 2012	28.3900	600,000	600,000	2,226,000	–	–
Total				**3,310,000**	**3,310,000**	**43,615,500**	**2,215,000**	**40,572,420**
Romanow	Dec 12, 2000	Dec 11, 2010	9.0250	200,000	200,000	4,615,000	200,000	4,615,000
	Dec 9, 2003	Dec 8, 2008	10.8750	220,000	220,000	4,669,500	220,000	4,669,500
	Dec 7, 2004	Dec 6, 2009	12.7175	228,000	228,000	4,419,210	228,000	4,419,210
	Dec 6, 2005	Dec 5, 2010	27.2850	124,000	124,000	597,060	83,080	400,030
	Dec 4, 2006	Dec 3, 2011	31.6000	160,000	160,000	80,000	54,400	27,200
	Dec 3, 2007	Dec 2, 2012	28.3900	180,000	180,000	667,800	–	–
Total				**1,112,000**	**1,112,000**	**15,048,570**	**785,480**	**14,130,940**
Murphy	Dec 7, 2004	Dec 6, 2009	12.7175	160,000	52,800	1,023,396	52,800	1,023,396
	Dec 6, 2005	Dec 5, 2010	27.2850	100,000	100,000	481,500	67,000	322,605
	Dec 4, 2006	Dec 3, 2011	31.6000	130,000	130,000	65,000	44,200	22,100
	Dec 3, 2007	Dec 2, 2012	28.3900	165,000	165,000	612,150	–	–
Total				**555,000**	**447,800**	**2,182,046**	**164,000**	**1,368,101**
Thomas	Dec 9, 2003	Dec 8, 2008	10.8750	128,000	128,000	2,716,800	128,000	2,716,800
	Dec 7, 2004	Dec 6, 2009	12.7175	160,000	160,000	3,101,200	160,000	3,101,200
	Dec 6, 2005	Dec 5, 2010	27.2850	100,000	100,000	481,500	67,000	322,605
	Dec 4, 2006	Dec 3, 2011	31.6000	130,000	130,000	65,000	44,200	22,100
	Dec 3, 2007	Dec 2, 2012	28.3900	165,000	165,000	612,150	–	–
Total				**683,000**	**683,000**	**6,976,650**	**399,200**	**6,162,705**
Nieuwenburg	Dec 9, 2003	Dec 8, 2008	10.8750	108,000	58,000	1,231,050	58,000	1,231,050
	Dec 7, 2004	Dec 6, 2009	12.7175	120,000	120,000	2,325,900	120,000	2,325,900
	Dec 6, 2005	Dec 5, 2010	27.2850	80,000	80,000	385,200	53,600	258,084
	Dec 4, 2006	Dec 3, 2011	31.6000	100,000	100,000	50,000	34,000	17,000
	Dec 3, 2007	Dec 2, 2012	28.3900	100,000	100,000	371,000	–	–
Total				**508,000**	**458,000**	**4,363,150**	**265,600**	**3,832,034**
Otten	Dec 7, 2004	Dec 6, 2009	US$10.5800	160,000	150,552	3,552,214	150,552	3,552,214
	Dec 6, 2005	Dec 5, 2010	US$23.6050	100,000	100,000	942,587	67,000	631,534
	Dec 4, 2006	Dec 3, 2011	US$27.5000	110,000	110,000	570,774	37,400	194,063
Total				**370,000**	**360,552**	**5,065,575**	**254,952**	**4,377,811**

Notes:

1 *Excludes grants that have been fully exercised.*

2 *The number and value of unvested TOPs can be determined by subtracting the vested TOPs from the vested and unvested TOPs. The value of unvested TOPs can be confirmed on page 150 in the Change of Control table.*

3 *The difference between the market value of Nexen common shares at year end (TSX—$32.10; NYSE—US $32.27) and the grant price of TOPs, times the number of TOPs.*

PENSION PLAN TABLES

All executives, except Mr. Otten, are members of Nexen's registered defined benefit pension plan and executive benefit plan. Mr. Otten was employed in the US and is a member of a qualified defined contribution pension plan and a non-qualified restoration plan, described on page 148.

Estimated Pension Benefit (Canada)

The normal form of benefit paid from these plans is a joint life and survivor benefit with a five-year guarantee. It is payable for the participant's lifetime and provides the spouse with a survivor benefit of 66 2/3% of the monthly payment. If the participant dies before receiving 60 monthly payments the five-year guarantee allows the surviving spouse to receive the balance of the 60 monthly payments first and then the reduced survivor pension of 66 2/3%.

In determining the estimated value of future pension benefits for Canadian executives, you must reference both tables below due to an amendment effective on January 1, 2005. The amendments increased the accrual formula on the defined benefit pension plan from 1.7% to a maximum of 2%. The first table is for actual credited service up to and including December 31, 2004, and the second table is for credited service on and after January 1, 2005. Also, please use the final average earnings outlined in the Pension Value Earned in 2007 (Canada) table on page 147 when referencing tables. The final average earnings will differ from the three-year average of base salary and cash incentive payments reported in the summary compensation table on page 142 due to the timing of base salary increases and because final average earnings include the lesser of the target bonus or actual bonus paid.

The table below shows the estimated annual pension a retiring executive would receive for credited service to and including December 31, 2004. The annual benefit is based on a pension accrual formula of 1.7% of final average earnings, less a plan CPP offset. It includes benefits from both the registered defined benefit pension plan and the executive benefit plan and assumes a retirement age of 60, the earliest age an individual may receive full retirement benefits.

	Years of Credited Service through Dec 31, 2004				
Final Average Earnings ($)	5	10	15	20	25
400,000	33,260	66,519	99,779	133,039	166,298
600,000	50,260	100,519	150,779	201,039	251,298
800,000	67,260	134,519	201,779	269,039	336,298
1,000,000	84,260	168,519	252,779	337,039	421,298
1,200,000	101,260	202,519	303,779	405,039	506,298
1,400,000	118,260	236,519	354,779	473,039	591,298
1,600,000	135,260	270,519	405,779	541,039	676,298
1,800,000	152,260	304,519	456,779	609,039	761,298
2,000,000	169,260	338,519	507,779	677,039	846,298
2,200,000	186,260	372,519	558,779	745,039	931,298
2,400,000	203,260	406,519	609,779	813,039	1,016,298

The table below shows the estimated annual pension benefit a retiring executive would receive for credited service earned on and after January 1, 2005, based on a pension benefit accrual formula of 2% of final average earnings, less a plan CPP offset. It includes benefits from both the registered defined benefit pension plan and executive benefit plan and assumes a retirement age of 60, the earliest age an individual may receive full retirement benefits.

	Years of Credited Service from Jan 1, 2005					
Final Average Earnings ($)	3	5	10	15	20	25
400,000	23,556	39,260	78,519	117,779	157,039	196,298
600,000	35,556	59,260	118,519	177,779	237,039	296,298
800,000	47,556	79,260	158,519	237,779	317,039	396,298
1,000,000	59,556	99,260	198,519	297,779	397,039	496,298
1,200,000	71,556	119,260	238,519	357,779	477,039	596,298
1,400,000	83,556	139,260	278,519	417,779	557,039	696,298
1,600,000	95,556	159,260	318,519	477,779	637,039	796,298
1,800,000	107,556	179,260	358,519	537,779	717,039	896,298
2,000,000	119,556	199,260	398,519	597,779	797,039	996,298
2,200,000	131,556	219,260	438,519	657,779	877,039	1,096,298
2,400,000	143,556	239,260	478,519	717,779	957,039	1,196,298

Pension Value Earned in 2007 (Canada)

The board must approve additional past service credits or accelerated service credits. No accelerated service credits were authorized in 2007. The table below shows additional past service credits authorized by the board for the executives who participate in the Canadian defined benefit pension plan and the executive benefit plan. The final average earnings reported for each executive include his:

- average base salary for the 36 highest paid consecutive months during the ten years before his retirement; plus
- annual cash incentive payments at the lesser of the target bonus or actual bonus paid, averaged over his final three years of participation.

No benefit payments were made to executives in the last fiscal year.

	Years of Credited Service				Accrued Annual Pension Benefit[1]		Estimated Annual Pension Benefit at Age 60[2]	
Name	Up to Dec 31, 2004 (#)	From Jan 1, 2005 (#)	Total (#)	Final Average Earnings[1] ($)	Under the Defined Benefit Pension Plan ($)	Under the Executive Benefit Plan[3] ($)	Under the Defined Benefit Pension Plan ($)	Under the Executive Benefit Plan[3] ($)
Fischer	20.58[4]	3.00	23.58	1,908,333	30,185	748,579	38,704	992,228
Romanow	17.50[4,5]	3.00	20.50	818,950	23,333	302,420	44,407	463,685
Murphy	18.67	3.00	21.67	666,278	48,148	200,053	61,315	305,566
Thomas	24.50[4]	3.00	27.50	651,183	38,889	267,328	55,000	419,576
Nieuwenburg	–[6]	3.00	3.00	461,199	6,667	72,818	34,426	198,907

Notes:

1 *All information as of December 31, 2007.*
2 *Age 60 is the earliest age an individual can receive full retirement benefits.*
3 *Represents the portion of the accrued annual pension benefit estimated under the executive benefit plan.*
4 *Ten years of additional past service credits were granted to each of Messrs. Fischer, Romanow and Thomas by the board in 2001.*
5 *Mr. Romanow joined the defined benefit pension plan after 7.25 years in the defined contribution pension plan. The pensionable bonus provision recognizes a pension benefit for Mr. Romanow based on his combined 27.75 years of service, while the base salary provision recognizes a pension benefit for his 20.5 years of defined benefit pension plan service only. The value of the pension benefit resulting from the additional 7.25 years is reflected in the pension benefit values above*
6 *Mr. Nieuwenburg joined the defined benefit pension plan after 23.58 years in the defined contribution pension plan*

Pension Benefit Obligation Increase in 2007 (Canada)

Our reported values use actuarial assumptions and methods consistent with those used to calculate pension liabilities and the related annual expense disclosed in our financial statements. As the assumptions reflect our best estimate of future events, our reported values may not be directly comparable to similar pension liability values disclosed by other companies.

Name	Obligation at Dec 31, 2006	Changes Related to Current Service Cost and Earnings Increases[1]	Changes Related to Financing Costs and Non-Compensation Assumption Changes[2]	Change in Obligation since Dec 31, 2006	Obligation at Dec 31, 2007
Fischer	11,157,800	949,300	552,900	1,502,200	12,660,000
Romanow	4,296,800	323,300	101,900	425,200	4,722,000
Murphy	3,287,800	583,300	169,900	753,200	4,041,000
Thomas	4,195,800	792,300	121,900	914,200	5,110,000
Nieuwenburg	933,800	267,300	24,900	292,200	1,226,000
Total	**23,872,000**	**2,915,500**	**971,500**	**3,887,000**	**27,759,000**

Notes:

1 *Includes the 2007 employer service cost, plus changes in compensation in excess of actuarial assumptions, less required member contributions to the plan.*
2 *Reflects the impact of interest on prior year's obligations, changes in discount rates used to measure the obligations and the impact of assumption and employee demographic changes.*

Pension Value Earned in 2007 (US)

Mr. Otten is the only executive who is a member of this US pension plan. He did not make any withdrawals in 2007.

Name	Contributions under the Defined Contribution Pension Plan	Contributions under the Non-Qualified Restoration Plan	Total Pension Compensation
Otten	22,314	34,970	57,284

ALL OTHER COMPENSATION

The total value of perquisites provided to any executive was less than $50,000 and less than 10% of the executive's total annual salary plus bonus in 2007. Certain perquisites shown below are at the maximum reimbursable amount available to executives. This maximum is often higher than what the executive actually claimed in the year. These perquisites are not available to the broader employee population.

	Perquisites			Other Compensation					
Name	Car Allowance	Other Perquisites[1]	Total	Life Insurance Premiums	Savings Plan Contributions	Amounts Paid by Canexus[2]	US Pension Contributions	Total	Total All Other Compensation
Fischer	31,200	10,500	41,700	1,440	76,500	–	–	77,940	119,640
Romanow	19,200	7,100	26,300	535	33,975	56,319	–	90,829	117,129
Murphy	19,200	7,100	26,300	1,164	29,750	–	–	30,914	57,214
Thomas	19,200	7,100	26,300	1,140	29,250	–	–	30,390	56,690
Nieuwenburg	19,200	7,100	26,300	835	21,640	–	–	22,475	48,775
Otten	13,054	7,723	20,777	2,132	13,325	–	57,284	72,741	93,518

Notes:

1 Represents a maximum reimbursement amount for financial counseling, luncheon club memberships, medical exam and security monitoring. For the CEO, this also includes a maximum reimbursement amount for a golf club membership.

2 Includes fees of $32,500, deferred trust units of Canexus valued at $19,560 and distributions on his trust units of $4,259.

TERMINATION ARRANGEMENTS

Nexen doesn't enter into employment service contracts. Depending on the conditions of termination, we treat executives and employees fairly as follows:

Events	Action
Resignation	▪ All salary and benefit programs cease ▪ Annual incentive bonus is not paid ▪ TOPs must be exercised within 90 days ▪ Pension paid as a commuted value or deferred benefit
Retirement	▪ Salary and benefit coverages cease except for a $5,000 life insurance policy ▪ Monthly benefit to cover the cost of provincial health care premiums continues ▪ Annual incentive bonus paid on a pro rata basis ▪ TOPs must be exercised within 18 months ▪ Pension paid as a monthly benefit
Death	▪ All salary and benefit programs cease except for a 1-year benefit ▪ coverage for surviving dependents and payout of any applicable insurance benefits ▪ Annual incentive bonus paid on a pro rata basis ▪ TOPs must be exercised within 18 months ▪ Pension paid as a commuted value or deferred benefit
Termination without cause	▪ All salary and benefit programs cease ▪ TOPs must be exercised within 90 days ▪ Pension paid as a commuted value or deferred benefit ▪ Severance provided on an individual basis reflecting service, age and salary level
Termination for cause	▪ All salary and benefit programs cease ▪ Annual incentive bonus is not paid ▪ TOPs must be exercised on termination ▪ Pension paid as a commuted value or deferred benefit

Payments on Resignation

The following table discloses the lump sum value of pension benefits accrued under the defined benefit pension plan and executive benefit plan for our top five executives had they resigned effective December 31, 2007. If they are over the age of 55 and have at least 10 years of Nexen service, they are deemed to have retired and a lump sum benefit option is not available. Also included in this table is the value of vested TOPs at December 31, 2007.

Name	Termination Scenario	Pension ($)	Value of Vested TOPs [1,2]	Total ($)
Fischer	Deemed Retirement	12,122,000	40,572,420	52,694,420
Romanow	Resignation	3,703,000	14,130,940	17,833,940
Murphy	Deemed Retirement	3,660,000	1,368,101	5,028,101
Thomas	Deemed Retirement	4,297,000	6,162,705	10,459,705
Nieuwenburg	Resignation	752,000	3,832,034	4,584,034

Notes:

1 Does not include unvested TOPs which will vest according to the TOPs plan over 18 months for deemed retirement or over 90 days for resignation.

2 The difference between the market value of Nexen common shares at year end of $32.10 and the grant price of TOPs, times the number of vested TOPs.

Change of Control Agreements

Nexen has entered into change of control agreements with Messrs. Fischer, Romanow, Murphy, Thomas, Nieuwenburg and other key executives. The agreements were effective October 1999, amended in December 2000 and then amended and restated in December 2001. We recognize that these executives are critical to Nexen's ongoing business. Therefore, it is vital we work to retain the executives, protect them from employment interruption caused by a change of control and treat them in a fair and equitable manner. Consistent with industry standards for executives in similar circumstances, there are no restrictions on future employment, or non-compete clauses in the agreements. Each year, the Compensation Committee reviews the estimated payments upon a change of control including the termination value of pension benefits due under the defined benefit pension plan and executive benefit plan.

Under these agreements, a change of control includes any acquisition of common shares or other securities that carries the right to cast more than 35% of the common share votes. Generally, it is any event that results in a person or group exercising effective control of Nexen.

If the executives terminate following a change of control, they are entitled to salary, target bonus and other compensatory benefits for the severance period specified below.

	Severance Period in Months on Change of Control	
Name	If Terminated	Upon Resignation [1]
Fischer	36	36
Romanow	36	30
Murphy	30	–
Thomas	30	–
Nieuwenburg	24	–

Note:

1 Within 12 months of change of control.

The next table outlines the estimated incremental payments executives would be entitled to, had a change of control occurred on December 31, 2007. Under the agreement, bonuses would be paid at target for the full severance period. A benefits uplift, equal to 13% of base salary, would be provided in lieu of medical, dental and life insurance coverage. In addition, the agreement provides a payment for other employee benefits, including car allowance and savings plan contributions during the severance period, and an allowance for financial counseling, security monitoring and career transition services.

Executives would also be entitled to incremental pension relating to their salary and annual incentive targets over the severance period. The pension value reported below reflects this, as well as a tax gross-up on the resulting lump sum payout. These additional pension benefits do not include any termination benefits that would be payable under the defined benefit pension plan and executive benefit plan if a termination or retirement occurred that was not triggered by a change of control.

Estimated Incremental Payment on Change of Control

Name	Severance Period (# of months)	Base Salary ($)	Bonus Target Value ($)	Benefits Uplift ($)	Other Employee Benefits ($)	Additional Lump Sum Value of Pension[1] ($)	Accelerated TOPs Value[2] ($)	Total Incremental Obligation ($)
Fischer	36	3,900,000	3,120,000	507,000	365,500	9,157,000	3,043,080	20,092,580
Romanow	36	1,725,000	1,035,000	224,250	199,000	3,879,000	917,630	7,979,880
Murphy	30	1,300,000	780,000	169,000	163,900	3,237,000	813,945	6,463,845
Thomas	30	1,300,000	780,000	169,000	163,900	3,905,000	813,945	7,131,845
Nieuwenburg	24	800,000	360,000	104,000	124,300	1,316,000	531,116	3,235,416
TOTAL		**9,025,000**	**6,075,000**	**1,173,250**	**1,016,600**	**21,494,000**	**6,119,716**	**44,903,566**

Notes:

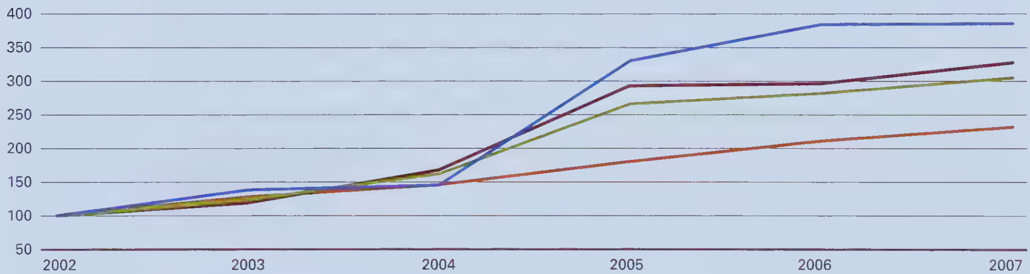
1 Does not include regular termination pension values which are reported in Payments on Resignation on page 149. Benefits payable under the defined benefit pension plan are funded from the pension trust and payable monthly if the executive is 55 or older.

2 Reflects the value of TOPs that automatically vest on a change of control, based on the number of TOPs with accelerated vesting, times the closing price of Nexen common shares on the TSX on December 31, 2007 of $32.10, less the exercise price.

SHARE PERFORMANCE GRAPH

The following graph shows the change in a $100 investment in Nexen common shares over the past five years, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index as at December 31, 2007. Our common shares are included in each of these indices.

Total Return Index Values[1]



	2002/12	2003/12	2004/12	2005/12	2006/12	2007/12
Nexen Inc.	100.00	138.21	144.57	330.52	384.10	385.26
S&P/TSX Oil & Gas Exploration & Production Index	100.00	120.15	169.02	293.50	297.38	327.52
S&P/TSX Energy Sector Index	100.00	124.97	162.82	266.10	282.22	305.45
S&P/TSX Composite Index	100.00	126.72	145.07	180.08	211.16	231.92

Note:

1 Assuming an investment of $100 and the reinvestment of dividends.

CORPORATE GOVERNANCE

Nexen's board takes its duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules of the Toronto Stock Exchange (TSX), NYSE, *National Policy 58-201—Corporate Governance Guidelines* and *Multilateral Instrument 52-110—Audit Committees*. Except as noted below, Nexen's corporate governance practices comply with those followed by domestic companies under NYSE listing standards.

Nexen has a DSU plan for non-executive directors as described on page 133. For this plan, Nexen follows the TSX rules which, unlike the NYSE rules, exempt plans from shareowner approval where the common shares issued under the plan are purchased on the open market rather than issuing new shares.

On February 21, 2008, our CEO certified to the NYSE that he was unaware of any violation by Nexen of the NYSE's corporate governance listing standards. Nexen also provided the required Annual Written Affirmation to the NYSE on February 21, 2008. Nexen also filed an Interim Written Affirmation on April 26, 2007, reporting changes to audit committee membership. As well, our CEO and CFO have certified the quality of Nexen's public disclosure to the SEC.

All Committee mandates, including those for the Audit, Compensation and Governance Committees, and our corporate governance policy and categorical standards are available at www.nexeninc.com, and we intend to provide disclosure in this manner. Shareowners wishing to receive a copy of these documents may contact the Governance Office by telephone at 403.699.4926, or by email at governance@nexeninc.com.

GOVERNANCE COMMITTEE REPORT

The Governance Committee assists the board to oversee implementation of our corporate governance programs, recommending nominees for director appointments and evaluating the board, its committees and all individual directors and chairs, to ensure we implement best-in-class corporate governance practices appropriate to Nexen.

All members of the Committee are independent and knowledgeable about our corporate governance programs. Six members of the Committee are skilled or expert in governance and board experience or diversity, the two areas of expertise most relevant to carrying out the Committee's mandate.

Changes to Committee Membership in 2007

Mr. Flanagan left the Committee and Mr. Newell joined in April 2007.

Key Activities in 2007

- Recommended revisions to the corporate governance policy, including a minimum attendance standard for directors, and the external communications policy;
- Reviewed our position on current governance issues, including say on pay (the concept of advisory votes on management compensation);
- Recommended the adoption of a modified majority vote by-law for the election of directors to the shareowners for approval;
- Recommended changes to committee memberships in light of Mr. Flanagan becoming non-independent as of July 1, 2007;
- Recommended updated mandates for the board, individual directors and all board committees;
- Recommended new and updated questions in the board performance evaluation based on rankings and comments received the previous year; and
- Consulted with Dr. Richard Leblanc, Assistant Professor of Corporate Governance, York University, on the board's performance evaluations.

The Board and Committees

The Committee reviews board and committee memberships annually, considering director independence and the skills and preferences of the directors. The board is comprised of 12 directors, which is large enough to permit a diversity of views and run the committees, without being so large as to detract from effectiveness. A skills matrix that sets out the various areas of expertise determined to be essential to ensure appropriate strategic direction and oversight is completed by all directors annually and reviewed by the Committee. The Committee's review of board experience indicates that the current skills mix is appropriate. The skills matrix is also used to assist with board recruitment.

Nominating a New Director for Election

The Committee identifies and assesses candidates for appointment or nomination to the board. Our forward-looking skills matrix has identified the skills with the greatest opportunity to strengthen the board upon retirement of two current directors in 2009.

Before recommending a new candidate to the board, the Committee considers his or her performance, independence, competencies, skills and financial acumen. Character and behavioural qualities, including credibility, integrity and communication skills are also taken into account. The Committee Chair and/or Board Chair meets with the candidate to discuss his or her interest and ability to devote sufficient time and resources to the position. Prior to nomination, potential directors must disclose possible conflicts of interest with Nexen and background checks, as appropriate, are completed.

The Committee maintains an evergreen list of potential directors whose skills complement the board and who the Committee recommends be asked to join the board if they are available when an opening arises.

The Committee will also consider any nominee for election as a director recommended by a shareowner. See page 153 for information on communicating with the board.

Performance Evaluations

The board and management work together to foster continuous, open and honest communication, where concerns are brought forward and dealt with as they occur. In this spirit, the annual board evaluation is seen as an opportunity to review the past year and consider contributions, successes and opportunities for improvement. The special report on our director evaluation process provided in our 2007 proxy circular, is available at www.nexeninc.com.

Our six-part performance evaluation review is our primary tool for determining who should be on the board. In light of the evaluation process, the board does not have a tenure policy and has flexible term limits. Nexen's average board tenure is 9.8 years. We do have a set retirement age of 75.

The Committee considered comments from the last evaluation when it updated the 2007 questionnaire to further explore CEO succession, crisis management, director recruitment, risk, compensation and the evaluation process itself.

The board rates its overall effectiveness on a ten-point scale, where 10 is the best. The average rating for 2007 was 9.23.

External Recognition and Verification

Nexen was recognized for its governance practices during 2007, including the following:

- Conference Board of Canada/Spencer Stuart 2007 National Award in Governance for the private sector;
- Named first, together with SNC-Lavalin Group Inc., on the Top 25 Boards in Canada by Canadian Business Magazine;
- Received an Honourable Mention for the 2007 Governance Gavel Award for Excellence in Director Disclosure from the Canadian Coalition for Good Governance;
- Received the Honourable Mention for Excellence in Corporate Governance Disclosure in the 2007 Corporate Reporting Awards from the Chartered Accountants of Canada;
- Named as having the Best Corporate Governance Practices in North America by IR Global Rankings; and
- Had an average 2007 global rating of 9.9 out of 10 and have a current rating of 9.5 from Governance Metrics International for governance practices and disclosure.

Committee Approval

The Committee has reviewed and discussed the governance disclosure in this document, including the information in the Board of Directors section on pages 129 through 133 and has recommended to the board that it be included in the proxy circular and, as appropriate, Form 10-K.

Submitted on behalf of the Governance Committee:

Dick Thomson, Chair
Kevin Jenkins
Anne McLellan
Eric Newell
Tom O'Neill
Francis Saville
John Willson

Ethics Policy

Under our ethics policy, all directors, officers and employees must demonstrate a commitment to ethical business practices and behaviour in all business relationships, both within and outside of Nexen. Employees are not permitted to commit an unethical, dishonest or illegal act or to instruct other employees to do so. Our ethics policy has been adopted as a code of ethics for our principal executive officer, principal financial officer and principal accounting officer or controller.

Any waivers of, or changes to the ethics policy must be board approved and disclosed. There has never been a waiver. The ethics policy was amended on December 3, 2007. We made minor revisions to update the name of an integrity-related policy. Our ethics policy provides for an external integrity helpline, in place since February 1, 2005.

Nexen's ethics policy is available at www.nexeninc.com and we intend to disclose any waivers of or changes to this policy online. Our ethics policy and any future amendments to it are filed on SEDAR at www.sedar.com. To request a copy of the policy, contact the Integrity Resource Centre by emailing integrity@nexeninc.com or by calling 403.699.4727.

Reporting Concerns

Please direct any concerns about Nexen's financial statements, accounting practices or internal controls to either:

- management or the Chair of the Audit Committee as set out in the ethics policy; or
- EthicsPoint, as set out below.

Employees, customers, suppliers, partners, shareowners and other external stakeholders who have a concern are encouraged to raise it with our Integrity Resource Centre:

By mail:	Nexen Inc. 801 - 7th Avenue SW Calgary, Alberta, Canada T2P 3P7 Attention: Integrity Resource Centre
By email:	integrity@nexeninc.com
By telephone:	403.699.4727

You may also report concerns through our integrity helpline—a secure reporting system, which is owned and managed by EthicsPoint, an independent third-party service provider. To find out more about our integrity helpline and for toll free numbers for other countries, access our web site at www.nexeninc.com and click on the "Integrity Helpline" link at the top of the page or access the helpline directly:

Online:	www.ethicspoint.com
By telephone:	1.866.384.4277 (toll-free in North America)

Communicating with the Board

Shareowners may write to the board or any member or members of the board in care of the following address:

By mail:	Nexen Inc. 801 - 7th Avenue SW Calgary, Alberta, Canada T2P 3P7 Attention: Governance Office
By email:	board@nexeninc.com

We receive a number of inquiries on a large range of subjects every day. The board has consulted with management to develop a process to assist in managing inquiries directed to the board or its members.

Letters and emails addressed to the board, any of its members or the independent directors, as a group, are reviewed to determine if a response from the board is appropriate. While the board oversees management, it does not participate in our day-to-day functions and operations and is not normally in the best position to respond to inquiries on those matters. Those inquiries will be directed to the appropriate personnel for response. The board has instructed the Governance Office to review all correspondence and, in its discretion, not forward items that are:

- not relevant to Nexen's operations, policies or philosophies;
- commercial in nature; or
- not appropriate for consideration by the board.

All inquiries will receive a response from the board or management. The Governance Office maintains a log of all correspondence sent to board members. Directors may review the log at any time and request copies of any correspondence received.

AUDIT COMMITTEE

See page 155 for a full report on the Audit Committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities. Based on information known to Nexen, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of Nexen's voting securities as at the date noted below.

Name and Address of Beneficial Owner	# of Shares Beneficially Owned	% of Shares	Effective Date
Jarislowsky, Fraser Limited[1] Suite 2005, 1010 Sherbrooke Street West Montreal, Quebec, Canada, H3A 2R7	53,090,139	10.05	January 31, 2008
Ontario Teachers' Pension Plan Board[2] 5650 Yonge Street Toronto, Ontario, Canada, M2M 4H5	52,677,672	9.97	January 8, 2008

Notes

1 *The beneficial owner has sole voting power over 44,870,646 shares, shared voting power over 8,219,493 shares and sole power to dispose of 53,090,139 shares and shared power to dispose of 268,680 shares.*

2 *The beneficial owner has sole voting power and power to dispose of all shares.*

SECURITY OWNERSHIP OF MANAGEMENT

At February 14, 2008, the following directors, certain executive officers, and all directors and executive officers as a group beneficially owned the following Nexen common shares:

Name of Beneficial Owner	Number of Shares[1]	Exercisable TOPs[2]
Charles W. Fischer	184,161	2,215,000
Dennis G. Flanagan	31,264	20,000
David A. Hentschel	70,814	100,000
S. Barry Jackson	72,000	–
Kevin J. Jenkins	12,362	60,000
A. Anne McLellan, P.C.	100	–
Eric P. Newell, O.C.	12,000	–
Thomas C. O'Neill	16,000	–
Francis M. Saville, Q.C.	48,860	71,004
Richard M. Thomson, O.C.	92,004	150,000
John M. Willson	22,004	–
Victor J. Zaleschuk	62,982	240,000
Laurence Murphy	125,504	164,000
Marvin F. Romanow	81,237	785,480
Roger D. Thomas	16,553	399,200
Gary H. Nieuwenburg	66,006	265,600
Douglas B. Otten	46,892	254,952
All directors and executive officers as a group (25 persons)	1,112,455	6,035,954

Notes

1 *The number of shares held and TOPs exercisable by each beneficial owner represents less than 1% of the shares outstanding.*

2 *Includes all TOPs exercisable within 60 days of February 14, 2008. All TOPs held by non-executive directors are vested.*

Under the terms of our TOPs plan, the board may grant options to officers and employees and, when previously allowed for, to directors. Nexen does not receive any consideration when options are granted.

Plan Category	Number of Securities to be Issued on Exercise of Outstanding TOP's	Weighted-Average Exercise Price of Outstanding TOP's	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by shareowners	27,402,722	$20/option	29,430,190
Equity compensation plans not approved by shareowners	–	–	–
Total	**27,402,722**	**$20/option**	**29,430,190**

Item 13. Certain Relationships and Related Transactions, and Director Independence

RELATED PARTY TRANSACTION

As a Canadian foreign private issuer, Nexen provides the disclosure required under Item 7.B. of Form 20-F dealing with "related party transactions." Nexen did not have any related party transactions in 2007 as defined under that standard. Certain other transactions described below which are not related party transactions, involving Nexen and certain of our directors, were entered into in 2007.

DIRECTOR INDEPENDENCE

Mr. Saville, was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta, until the end of January 2004. Since February 1, 2004, he has been counsel with the firm. FMC provided legal services to us in each of the last five years. Mr. Saville does not solicit or participate in these services and does not receive any portion of the fees we pay to FMC. He is independent under our categorical standards.

Ms. McLellan, has been counsel with Bennett Jones (BJ), Barristers and Solicitors, Edmonton, Alberta since June 27, 2006. BJ provided legal services to us in each of the last five years. Ms. McLellan does not solicit or participate in those services and does not receive any portion of the fees we pay to BJ. She is independent under to our categorical standards.

Mr. Fischer is not independent as he is President and CEO.

Mr. Flanagan is not independent as his son is Senior Vice President, Engineering, of TriAxon Resources Ltd. (TriAxon). In 2006, TriAxon acquired a company that was party to contracts with a subsidiary of Nexen. Under one of the contracts Nexen paid approximately $4.5 million to TriAxon between July and December 2006 for products purchased at market price. Accordingly, Mr. Flanagan is not technically independent as of July 1, 2007. Mr. Flanagan was not aware that the company acquired by TriAxon held contracts with Nexen. The board has determined that Mr. Flanagan's independence of mind has not been compromised by this transaction and, accordingly, the board continues to include him in their meetings without management.

Item 14. Principal Accounting Fees and Services

AUDIT COMMITTEE REPORT

The Audit Committee is responsible for appointing (subject to shareowner approval), compensating and overseeing the Independent Registered Chartered Accountants (IRCAs). The IRCAs are accountable to and report directly to the Committee, and understand that they must maintain an open and transparent relationship with the Committee, as representatives of the shareowners.

All members of the Committee are independent and knowledgeable about our financial reporting controls, and internal and external audit processes. Five members are skilled or expert in financial acumen, particularly financial accounting, reporting and internal controls, the area of expertise most relevant to carrying out the Committee's mandate.

The Committee assists the board in overseeing internal accounting and financial reporting controls, internal and external audit processes, and implementation of the ethics policy.

Management is responsible for our internal controls and financial reporting process. The IRCAs are responsible for performing and reporting on an independent audit of our: (i) consolidated financial statements according to generally accepted auditing standards; and, (ii) internal control over financial reporting according to the standards of the Public Company Accounting Oversight Board. The Committee's responsibility is to monitor and oversee these processes.

Changes to Committee Membership in 2007

Mr. Flanagan left the Committee and Mr. Newell joined April 2007.

Key Activities for 2007

- Met separately with management and the IRCAs to review the December 31, 2007 consolidated financial statements;
- Discussed with the IRCAs matters required by Canadian regulators under Section 5751 of the General Assurance and Auditing Standards of the Canadian Institute of Chartered Accountants "Communications with Those having Oversight Responsibility for the Financial Reporting Process" and by US regulators under the Statement on Auditing Standards No. 61 "Communication with Audit Committees" issued by the American Institute of Certified Public Accountants;
- Received written disclosures from the IRCAs required by the SEC according to the Independence Standards BoardStandard No. 1 "Independence Discussions with Audit Committees";
- Discussed with the IRCAs that firm's independence;
- Based on the reviews and discussions referred to above, recommended to the board that the audited consolidated financial statements be included in Nexen's annual report on Form 10-K for the year ended December 31, 2007;
- Oversaw Section 404 Sarbanes-Oxley compliance activities undertaken by management to report on the effectiveness of internal control over financial reporting as at December 31, 2007;

- reviewed and approved the quarterly consolidated financial statements; and
- Recommended changes to the ethics policy.

Audit Partner Rotation

In compliance with applicable law, the lead audit partner of our IRCAs is replaced every five years.

Section 404 of Sarbanes-Oxley

Nexen is a voluntary filer of Form 10-K in the US and has complied with the requirements of Section 404 of Sarbanes-Oxley since December 31, 2004. During 2007, management evaluated the effectiveness of our internal control over financial reporting and concluded that it was effective as of December 31, 2007. This assessment was audited by the IRCAs in 2006 as part of the integrated audit of the consolidated financial statements. This particular audit is no longer required as part of the IRCA's integrated audit due to US regulatory changes. The Committee's mandate, available at www.nexeninc.com, has been updated accordingly. Their integrated audit report for 2007 is included in our Form 10-K.

IRCA Engagement and Fees Billed

Before Deloitte & Touche LLP, the IRCA is engaged by Nexen or its subsidiaries to render additional audit or non-audit services, the engagement is approved by the Committee. All audit, audit-related, tax and other services provided by Deloitte & Touche LLP since May 6, 2003 have been approved by the Committee.

Type of Fee	Billed in 2006	Billed in 2007	Percentage of Total Fees Billed in 2007
Audit Fees			
For the integrated audit of Nexen's consolidated financial statements included in our annual report on Form 10-K	2,332,500 [1]	2,966,000 [2]	
For the integrated audit of the consolidated financial statements of Canexus [3]	302,900	145,000 [4]	
For the first, second and third quarter reviews of Nexen's consolidated financial statements included in Form 10-Qs	72,000	90,000	
For the first, second and third quarter reviews of the consolidated financial statements of Canexus [3]	45,000	45,000	
For comfort letters and submissions to commissions	2,500	153,500	
Total Audit Fees	**2,754,900**	**3,399,500**	**76%**
Audit-Related Fees–Nexen and Canexus [3]			
For the annual audits and quarterly reviews of subsidiary financial statements and employee benefit plans	719,500	828,100	
Total Audit-Related Fees	**719,500**	**828,100**	**19%**
Tax Fees–Nexen and Canexus [3]			
For tax return preparation assistance and tax-related consultation	84,300	116,400	
Total Tax Fees	84,300	116,400	3%
All Other Fees	86,000 [5]	110,600 [5]	2%
Total Annual Fees	**3,644,700**	**4,454,600**	**100%**

Notes:

1 Consisting of $1,032,500 to complete the 2005 audit and $1,300,000 to commence the 2006 audit.
2 Consisting of $1,366,000 to complete the 2006 audit and $1,600,000 to commence the 2007 audit.
3 Includes fees for Canexus Income Fund, Canexus Limited Partnership and its subsidiaries.
4 Consisting of $95,000 to complete the 2006 audit and $50,000 to commence the 2007 audit.
5 Annual renewal fees for an upstream information database used in our UK office.

Committee Approval

The Committee is of the view that the provision of services by Deloitte & Touche LLP described in "All Other Fees" above is compatible with maintaining that firm's independence.

Based on the Committee's discussions with management and the IRCAs, and its review of the representations of management and the IRCAs, the Committee recommended to the board that the audited consolidated financial statements be included in Nexen's annual report on Form 10-K for the year ended December 31, 2007.

Submitted on behalf of the Audit Committee:

Tom O'Neill, Chair
Eric Newell
Barry Jackson
Dick Thomson
Kevin Jenkins
John Willson

PART IV
Item 15. Exhibits, Financial Statement Schedules

FINANCIAL STATEMENTS AND SCHEDULES

We refer you to the index to Financial Statements and Supplementary Data in Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted because they are not required or applicable, or the required information is shown in the Consolidated Financial Statements or notes.

EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

2.2 Agreement for the Sale and Purchase of EnCana (U.K.) Limited, between EnCana (U.K.) Holdings Limited and Nexen Energy Holdings International Limited dated October 28, 2004 (filed as Exhibit 2.1 to Form 8-K dated October 29, 2004).

3.14 Restated Certificate and Articles of Incorporation of the Registrant dated May 20, 2005 (filed as Exhibit 3.12 to Form 10-Q for the quarterly period ended June 30, 2005).

3.15 By-Law No. 3 of the Registrant enacted December 4, 2006, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 3.15 to Form 8-K dated December 5, 2006).

3.16 Certificate and Articles of Amendment of the Registrant dated April 26, 2007 (filed as Exhibit 3.16 to Form 8-K dated April 27, 2007).

4.42 Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company providing for the issue of debt securities from time to time (filed as Exhibit 4.42 to Form 10-K for the year ended December 31, 2003).

4.43 First Supplemental Indenture dated April 28, 1998 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$200 million, 7.40% notes due 2028 (filed as Exhibit 4.43 to Form 10-K for the year ended December 31, 2003).

4.46 Third Supplemental Indenture dated March 11, 2002 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of $500 million, 7.85% notes due 2032 (filed as Exhibit 4.46 to Form 10-K for the year ended December 31, 2003).

4.47 Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of subordinated notes from time to time (filed as Exhibit 4.47 to Form 10-K for the year ended December 31, 2003).

4.48 Officer's Certificate dated November 4, 2003 pursuant to the Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issuance of US$460 million, 7.35% subordinated notes due 2043 (filed as Exhibit 4.48 to Form 10-K for the year ended December 31, 2003).

4.51 Fourth Supplemental Indenture dated November 20, 2003 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$500 million, 5.05% notes due 2013 (filed as Exhibit 4.51 to Form 10-K for the year ended December 31, 2003).

4.53 Fifth Supplemental Indenture dated March 10, 2005 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$250 million, 5.20% notes due 2015 and the issuance of US$790 million, 5.875% notes due 2035 (filed as Exhibit 10.1 to Form 8-K dated March 11, 2005).

4.54 Amended and Restated Shareholder Rights Plan Agreement dated April 27, 2005 between the Registrant and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A (filed as Exhibit 4.54 to Form 10-K for the year ended December 31, 2005).

4.55 Senior Debt Indenture dated May 4, 2007 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of senior notes from time to time (filed as Exhibit 4.1 to Form 8-K dated May 7, 2007).

4.56 First Supplemental Indenture dated May 4, 2007 to the Trust Indenture dated May 4, 2007 between the Registrant and Deutsche Bank Trust Company Americas pertaining to the issuance of US$250 million, 5.65% notes due 2017 and the issuance of US$1.25 billion, 6.40% notes due 2037 (filed as Exhibit 4.2 to Form 8-K dated May 7, 2007).

10.40 Amended and Restated Change of Control Agreements with Executive Officers dated during December, 2001 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2001).

10.41 Indemnification Agreements made between the Registrant and its directors and officers during 2002 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002).

10.42 Indemnification Agreement made between the Registrant and one of its directors, Eric P. Newell, as of January 5, 2004 (filed as Exhibit 10.42 to Form 10-K for the year ended December 31, 2003).

10.43 Credit Agreement dated as of July 22, 2005 between the Registrant and the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 28, 2005).

10.44 Guarantee dated as of July 22, 2005 as Schedule K to the Credit Agreement (filed as Exhibit 10.2 to Form 8-K dated July 28, 2005).

10.46 Indemnification Agreement made between the Registrant and one of its directors, A. Anne McLellan P.C., as of July 5, 2006 (filed as Exhibit 10.2 to Form 8-K dated July 20, 2006).

10.47 Second Amending Agreement dated July 14, 2006 to the Credit Agreement, dated as of July 22, 2005, between the Registrant and the Toronto-Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 20, 2006).

10.48 Indemnification Agreement made between the Registrant and Brendon Muller dated April 9, 2007 (filed as Exhibit 10.48 to Form 8-K dated April 12, 2007).

10.49 Amended and Restated Change of Control Agreement with Roger Thomas dated during December 2001 (filed as Exhibit 10.48 to Form 10-Q for the quarterly period ended March 31, 2007).

10.50 Pricing Agreement dated May 1, 2007 among the Registrant and Banc of America Securities LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as Underwriters (filed as Exhibit 10.1 to Form 8-K dated May 7, 2007).

10.51* Change of Control Agreement with Gary Nieuwenburg dated during January 2002.

11.1* Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2007.

21.1* Subsidiaries of the Registrant.

23.1* Consent of Independent Registered Chartered Accountants.

23.2* Consent of William M. Cobb & Associates, Inc.

23.3* Consent of Ryder Scott Company, L.P.

23.4* Consent of McDaniel & Associates Consultants Ltd.

23.5* Consent of DeGolyer and MacNaughton.

31.1* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1* Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2* Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1* Opinion of Internal Qualified Reserves Evaluator on National Instrument 51-101 Form F2 as required by certain Canadian securities regulatory authorities.

* *Filed with this Form 10-K.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 21, 2008.

NEXEN INC.

By: /s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 21, 2008.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ A. Anne McLellan, Director
A. Anne McLellan, Director

/s/ Eric P. Newell
Eric P. Newell, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Brendon T. Muller
Brendon T. Muller
Controller
(Principal Accounting Officer)

/s/ Eric B. Miller
Eric B. Miller
Vice President, General Counsel
and Secretary

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Senior Vice President, Corporate Planning
and Business Development

EXHIBIT 31.1

Certifications

I, Charles W. Fischer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2008

/s/ Charles W. Fischer
Charles W. Fischer
President and Chief Executive Officer

EXHIBIT 31.2

Certifications

I, Marvin F. Romanow, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2008

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President
and Chief Financial Officer

EXHIBIT 32.1

Certification Of Periodic Report

I, Charles W. Fischer, President and Chief Executive Officer of Nexen Inc., a Canadian Corporation (the "Company" certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2008

/s/ Charles W. Fischer
Charles W. Fischer
President
and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

EXHIBIT 32.2

Certification Of Periodic Report

I, Marvin F. Romanow, Executive Vice President and Chief Financial Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2008

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President
and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

corporate **and other**

Our consistent historical performance, strong leadership and high-quality reserves provide a solid foundation for delivering what's next.

CORPORATE AND OTHER

Did you know 98% of our proved reserves were assessed by independent qualified consultants in 2007? Learn more about our reserve estimates at ***www.nexeninc.com/reports/A8.asp***

reserves

Reserve bookings capture only a glimpse of what's next. In 2007, we added 102 million boe of proved reserves, replacing about 110% of our annual production. Our year-end proved and probable reserves totaled 2.0 billion boe. Yet there's more—just look at our oil sands. So far we've booked 791 million barrels of proved and probable reserves for Phases 1 and 2 of Long Lake—but we have enough land to potentially develop up to 10 phases. Our booked reserves also reflect little for our undeveloped discoveries in the Gulf of Mexico and UK, and the unconventional CBM and shale gas in our leases in western Canada. As these projects take shape, we expect to book significantly more reserves, proving **what's next**.

Before Royalties, Year-end Pricing

	Oil and Gas Activities										Mining	
	International				United States		Canada					
	Yemen	United Kingdom		Other Intl								
(mmboe)	Oil	Oil	Gas	Oil	Oil	Gas	Oil	Gas	Bitumen	Total Oil and Gas	Syncrude[3]	Total Oil, Gas and Mining
Proved Reserves[1]												
December 31, 2006	66	179	3	40	34	39	57	61	246	725	324	1,049
Extensions and Discoveries	2	10	–	–	1	3	1	6	–	23	8	31
Acquisitions	–	1	–	–	3	8	–	–	–	12	–	12
Dispositions	–	–	–	–	–	(2)	–	–	–	(2)	–	(2)
Revisions	1	43	1	–	(7)	(5)	4	2	22	61	–	61
Production	(28)[4]	(30)	–	(2)	(6)	(6)	(6)	(7)	–	(85)	(8)	(93)
December 31, 2007	**41**	**203**	**4**	**38**	**25**	**37**	**56**	**62**	**268**	**734**	**324**	**1,058**
Probable Reserves[1,2]												
December 31, 2006	22	152	8	59	69	30	22	40	154	556	46	602
Extensions, Discoveries and Conversions	(4)	(29)	(2)	–	0	2	1	(2)	378	344	–	343
Acquisitions	–	2	–	–	1	6	–	–	–	9	–	9
Dispositions	–	–	–	–	(15)	(9)	–	–	–	(24)	–	(24)
Revisions	(3)	14	(1)	1	(16)	(8)	1	(4)	(9)	(25)	–	(24)
December 31, 2007	**15**	**139**	**5**	**60**	**39**	**21**	**24**	**34**	**523**	**860**	**46**	**906**
Proved + Probable Reserves[1,2]												
December 31, 2006	88	331	11	99	103	69	79	101	400	1,281	370	1,651
Extensions, Discoveries and Conversions	(2)	(19)	(2)	–	1	5	2	4	378	367	8	374
Acquisitions	–	3	–	–	4	14	–	–	–	21	–	21
Dispositions	–	–	–	–	(15)	(11)	–	–	–	(26)	–	(26)
Revisions	(2)	57	–	1	(23)	(13)	5	(2)	13	36	–	37
Production	(28)[4]	(30)	–	(2)	(6)	(6)	(6)	(7)	–	(85)	(8)	(93)
December 31, 2007	**56**	**342**	**9**	**98**	**64**	**58**	**80**	**96**	**791**	**1,594**	**370**	**1,964**

1 *We internally evaluate all of our reserves and have at least 80% of our proved reserves assessed by independent qualified consultants each year; 98% were assessed this year. Our reserves are also reviewed and approved by our Reserves Committee and our Board of Directors. Reserves represent our working interest before royalties at year-end constant pricing using Securities and Exchange Commission rules. Gas is converted to equivalent oil at a 6:1 ratio.*

2 *Probable reserves are determined according to SPE/WPC definitions. US investors should read the Cautionary Note to US Investors at the end of this report.*

3 *US investors should read the Cautionary Note to US Investors at the end of this report.*

4 *Production includes volumes used for fuel in Yemen.*

performance review

(Cdn$ millions, except share and production data)	2007	2006	2005	2004	2003
Highlights					
Net Sales [1]	5,583	3,936	3,932	2,944	2,632
Cash Flow from Operations [2]	3,458	2,669	2,403	1,942	1,795
Per Common Share ($/share)	6.56	5.09	4.62	3.78	3.63
Net Income	1,086	601	1,140	793	578
Per Common Share ($/share)	2.06	1.15	2.19	1.54	1.17
Capital Expenditures	3,401	3,330	2,638	1,681	1,494
Business Acquisitions	–	78	–	2,583	–
Dispositions	4	27	911	34	293
Production [3,4]					
Production Before Royalties (mboe/d)	254	212	242	250	269
Production After Royalties (mboe/d)	207	156	173	174	185
Financial Position					
Working Capital	412	476	29	40	1,399
Property, Plant and Equipment, Net	12,498	11,739	9,594	8,643	4,550
Total Assets	18,075	17,156	14,590	12,383	7,717
Net Debt [5]	4,404	4,730	3,639	4,285	1,430
Long-Term Debt	4,610	4,673	3,687	4,259	3,089
Shareholders' Equity	5,610	4,636	3,996	2,867	2,075
Shares and Dividends					
Common Shares Outstanding (millions)	528.3	525.0	522.2	516.8	502.4
Number of Registered Common Shareholders	1,569	1,454	1,294	1,329	1,420
Closing Common Share Price (TSX) (Cdn$/share)	32.10	32.10	27.71	12.18	11.73
Dividends Declared per Common Share (Cdn$/share)	0.10	0.10	0.10	0.10	0.08
Cash Flow from Operations [2]					
Oil and Gas					
United Kingdom	2,101	477	284	30	–
Yemen	664	877	929	581	530
Canada	179	229	397	426	490
United States	480	573	667	700	623
Other Countries	87	94	48	57	64
Marketing	73	432	138	100	126
Syncrude	319	240	223	183	105
	3,903	2,922	2,686	2,077	1,938
Chemicals	90	83	95	82	74
	3,993	3,005	2,781	2,159	2,012
Interest and Other Corporate Items	(350)	(254)	(335)	(196)	(208)
Income Taxes	(185)	(82)	(43)	(21)	(9)
Total Cash Flow from Operations	**3,458**	**2,669**	**2,403**	**1,942**	**1,795**

1 *Represents net sales from continuing operations.*
2 *Cash flow from operations is defined as cash generated from operating activities before changes in non-cash working capital and other.*
3 *Production is Nexen's working interest share and includes our share of production from Syncrude.*
4 *Natural gas is converted at 6 mcf per equivalent barrel of oil.*
5 *Net Debt is defined as long-term debt and short-term borrowings less cash and cash equivalents.*

Did you know our Statistical Supplement provides years of historical financial and operating information? Download your copy at ***www.nexeninc.com/reports/A9.asp***

performance review

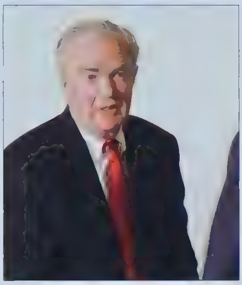
	2007	2006	2005	2004	2003
Production Before Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	81.2	16.9	12.6	1.5	–
Yemen	71.6	92.9	112.7	107.3	116.8
Canada	17.1	20.0	29.2	36.2	46.3
United States	16.4	17.0	22.2	30.0	28.3
Australia	–	–	–	2.7	6.1
Other Countries	6.2	6.3	5.6	5.3	5.4
Syncrude	22.1	18.7	15.5	17.2	15.3
	214.6	171.8	197.8	200.2	218.2
Natural Gas (mmcf/d)					
United Kingdom	16	20	23	3	–
Canada	118	108	124	146	158
United States	101	111	116	148	145
	235	239	263	297	303
Total Production Before Royalties (mboe/d)	**254**	**212**	**242**	**250**	**269**
Production After Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	81.2	16.9	12.6	1.5	–
Yemen	39.8	51.8	60.6	53.5	57.5
Canada	13.4	15.8	22.6	28.2	35.4
United States	14.5	15.0	19.6	26.5	25.0
Australia	–	–	–	2.5	5.6
Other Countries	5.7	5.7	5.1	4.7	4.6
Syncrude	18.8	16.9	15.3	16.6	15.2
	173.4	122.1	135.8	133.5	143.3
Natural Gas (mmcf/d)					
United Kingdom	16	20	23	3	–
Canada	98	91	101	115	125
United States	86	94	99	126	122
	200	205	223	244	247
Total Production After Royalties (mboe/d)	**207**	**156**	**173**	**174**	**185**
Oil and Gas Cash Netback Before Royalties[1] ($/boe)					
Producing Assets					
United Kingdom	67.85	55.53	42.93	39.19	–
Yemen	25.52	26.35	22.56	14.99	12.58
Canada	20.07	22.87	25.46	21.24	19.46
United States	42.28	40.42	45.85	35.35	32.48
Australia	–	–	–	14.28	21.10
Syncrude	41.94	37.86	43.34	31.07	20.92
Other Countries	61.94	57.71	49.18	35.82	25.06
Company-Wide Oil and Gas	**43.22**	**32.75**	**30.57**	**22.66**	**19.24**

1 *Defined as average sales price less royalties and other, operating costs and in-country taxes in Yemen. Calculation details can be found in the Statistical Supplement on our website.*

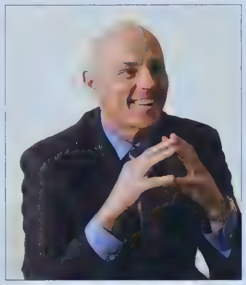
executive management

Charles W. Fischer
President and
Chief Executive Officer

Marvin F. Romanow
Executive Vice President
and Chief Financial Officer



Laurence Murphy
Executive Vice President,
International Oil and Gas



Roger D. Thomas
Executive Vice President,
North America

Gary H. Nieuwenburg
Senior Vice President,
Synthetic Crude

Kevin J. Reinhart
Senior Vice President,
Corporate Planning and
Business Development

Brian C. Reinsborough
Senior Vice President,
United States Oil and Gas

Tim J. Thomas
Senior Vice President,
Canadian Oil and Gas

Robert J. Black
Vice President,
Energy Marketing

Randy J. Jahrig
Vice President,
Human Resources and
Corporate Services

Kim D. McKenzie
Vice President and
Chief Information Officer

Eric B. Miller
Vice President, General Counsel
and Secretary

Una M. Power
Treasurer

Brendon T. Muller
Controller

Did you know our board of directors was ranked the top board in Canada in 2007? Learn more about our directors by visiting **www.nexeninc.com/reports/A10.asp**

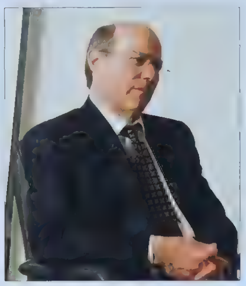
board of directors

Francis M. Saville, Q.C.
Chair of the Board
Calgary, Alberta,
Canada

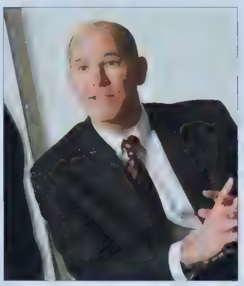
Charles W. Fischer
President and CEO
Calgary, Alberta,
Canada

Dennis G. Flanagan
Calgary, Alberta,
Canada

David A. Hentschel
Tulsa, Oklahoma,
United States



S. Barry Jackson
Calgary, Alberta,
Canada

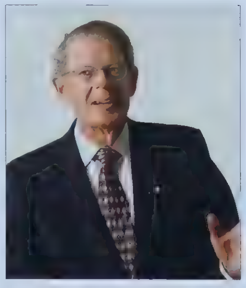


Kevin J. Jenkins
Calgary, Alberta,
Canada

The Honourable A. Anne McLellan, P.C.
Edmonton, Alberta,
Canada

Eric P. Newell, O.C.
Edmonton, Alberta,
Canada

Thomas C. O'Neill
Toronto, Ontario,
Canada



Richard M. Thomson, O.C.
Toronto, Ontario,
Canada

John M. Willson
Vancouver, British Columbia,
Canada

Victor J. Zaleschuk
Calgary, Alberta,
Canada

corporate information

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www.nexeninc.com

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Vice President, Investor Relations
T 403.699.4688
F 403.699.5730
mike_harris@nexeninc.com

Annual General and Special Meeting
11:00 a.m. M.T.
Tuesday, April 29, 2008
The Metropolitan Centre
333 - 4th Avenue SW
Calgary, Alberta, Canada

Stock Symbol—NXY
Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Preferred Securities
7.35% Subordinated Notes
TSX—NXY.PR.U
NYSE—NXYPRB

Common Share Transfer Agent and Registrars
CIBC Mellon Trust Company
Calgary, Toronto, Montreal and Vancouver, Canada

The Bank of New York Mellon
Jersey City, New Jersey, US

Dividend Reinvestment Plan
The offering circular (and for US residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or at www.cibcmellon.com

Auditors
Deloitte & Touche LLP
Calgary, Alberta, Canada

Conversions
Natural gas is converted at 6 mcf per equivalent barrel of oil.

Dollar Amounts
In Canadian dollars unless otherwise stated.

Operating Entities

Canada
Nexen Oil Sands Partnership

United States
Nexen Petroleum Offshore U.S.A. Inc.
Nexen Petroleum U.S.A. Inc.

International
Canadian Nexen Petroleum East Al Hajr Ltd.
Canadian Nexen Petroleum Yemen
Nexen Ettrick U.K. Limited
Nexen Exploration Norge AS
Nexen Exploration U.K. Limited
Nexen Petroleum Colombia Limited
Nexen Petroleum Nigeria Limited
Nexen Petroleum U.K. Limited

Marketing
Nexen Energy Marketing Europe Limited
Nexen Energy Marketing London Limited
Nexen Marketing
Nexen Marketing International Ltd.
Nexen Marketing Singapore Pte. Ltd.
Nexen Marketing U.S.A. Inc.

Chemicals
Canexus Chemicals Canada Limited Partnership
Canexus U.S. Inc.
Canexus Química Brasil Ltda.

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officers

Francis M. Saville, Q.C.
Chair of the Board

Charles W. Fischer
President and Chief Executive Officer

Marvin F. Romanow
Executive Vice President and Chief Financial Officer

Laurence Murphy
Executive Vice President, International Oil and Gas

Roger D. Thomas
Executive Vice President, North America

Gary H. Nieuwenburg
Senior Vice President, Synthetic Crude

Kevin J. Reinhart
Senior Vice President, Corporate Planning and Business Development

Brian C. Reinsborough
Senior Vice President, United States Oil and Gas

Tim J. Thomas
Senior Vice President, Canadian Oil and Gas

Randy J. Jahrig
Vice President, Human Resources and Corporate Services

Kim D. McKenzie
Vice President and Chief Information Officer

Eric B. Miller
Vice President, General Counsel and Secretary

Una M. Power
Treasurer

Brendon T. Muller
Controller

Rick C. Beingessner
Assistant Secretary

Sylvia L. Groves
Assistant Secretary

For more information on our officers and directors, please see Item 10 in our Form 10-K.

feedback

Your opinion counts

At Nexen, we strive to provide meaningful, easy-to-read communications so you may understand our results, future plans and values. Please fill out a short online survey so we can continue offering you the best disclosure possible.

www.nexeninc.com/survey/AR07.asp

Please visit our website to learn more.

About Nexen	www.nexeninc.com/about_us/
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Sustainability	www.nexeninc.com/sustainability/
Governance	www.nexeninc.com/governance/
Investors	www.nexeninc.com/investors/
Newsroom	www.nexeninc.com/newsroom/
Careers	www.nexeninc.com/careers/

forward-looking statements

Certain statements in this report constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information ("forward-looking statements") are generally identifiable by the terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil, natural gas or chemicals prices, future production levels, future cost recovery oil revenues from our Yemen operations, future capital expenditures and their allocation to exploration and development activities, future earnings, future asset dispositions, future sources of funding for our capital program, future debt levels, possible commerciality, development plans or capacity expansions, future ability to execute dispositions of assets or businesses, future cash flows and their uses, future drilling of new wells, ultimate recoverability of reserves or resources, expected finding and development costs, expected operating costs, future demand for chemicals products, estimates on a per share basis, sales, future expenditures and future allowances relating to environmental matters and dates by which certain areas will be developed or will come on stream, and changes in any of the foregoing are forward-looking statements. Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas and chemicals products; our ability to explore, develop, produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; volatility in energy trading markets; foreign-currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; and political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement. Readers should also refer to Items 1A and 7A in our 2007 Annual Report on Form 10-K for further discussion of the risk factors.

Cautionary Note to US Investors—The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to discuss only proved reserves that are supported by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this disclosure, we may refer to "recoverable reserves", "probable reserves" and "recoverable resources" which are inherently more uncertain than proved reserves. These terms are not used in our filings with the SEC. Our reserves and related performance measures represent our working interest before royalties, unless otherwise indicated. Please refer to our Annual Report on Form 10-K available from us or the SEC for further reserve disclosure.

In addition, under SEC regulations, the Syncrude oil sands operations are considered mining activities rather than oil and gas activities. Production, reserves and related measures in this disclosure include results from the Company's share of Syncrude. Under SEC regulations, we are required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil we will produce and sell from Long Lake.

Cautionary Note to Canadian Investors—Nexen is required to disclose oil and gas activities under *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. However, the Canadian securities regulatory authorities (CSA) have granted us exemptions from certain provisions of NI 51-101 to permit US-style disclosure. These exemptions were sought because we are a US Securities and Exchange Commission (SEC) registrant and our securities regulatory disclosures, including Form 10-K and other related forms, must comply with SEC requirements. Our disclosures may differ from those of Canadian companies who have not received similar exemptions under NI 51-101.

Please read the "Special Note to Canadian Investors" in Item 7A in our 2007 Annual Report on Form 10-K, for a summary of the exemption granted by the CSA and the major differences between SEC requirements and NI 51-101. The summary is not intended to be all-inclusive or to convey specific advice. Reserve estimation is highly technical and requires professional collaboration and judgment.

Because reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.

Please note that the differences between SEC requirements and NI 51-101 may be material.

Our probable reserves disclosure applies the Society of Petroleum Engineers/World Petroleum Council (SPE/WPC) definition for probable reserves. *The Canadian Oil and Gas Evaluation Handbook* states there should not be a significant difference in estimated probable reserve quantities using the SPE/WPC definition versus NI 51-101.

In this disclosure, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.


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Nexen is a Canadian-based global energy company growing value responsibly. Our common shares trade on the TSX in Canada and NYSE in the US.

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